CRITICAL SOUR DRILLING

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

IRP VOLUME 1 – 2008

SANCTION

ENFORM

Edition 5
Sanction Date January 2004
Copyright/Right to Reproduce

Copyright for this document is held by Enform, 2008. All rights reserved. No part of this document may be reproduced, republished, redistributed, stored in a retrieval system, or transmitted unless the user references the copyright ownership of Enform.

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 owner, operator, and contractors 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 the IRP to judge its suitability for a particular application.

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

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in the IRP. However, DACC, its subcommittees, and individual contributors make no representation, warranty, or guarantee in connection with the publication of the contents of any IRP recommendation, and hereby disclaim liability or responsibility for loss or damage resulting from the use of this IRP, or for any violation of any legislative requirements.

Availability

This document, as well as future editions, is available from

Enform
1538 – 25th Avenue NE
Calgary, AB T2E 8Y3
Phone: (403) 250-9606
Fax: (403) 291-9408
Website: www.enform.ca
TABLE OF CONTENTS

Table of Contents .......................................................................................................................... i
List of Figures .............................................................................................................................. x
List of Tables .............................................................................................................................. xi
1.1. Acknowledgements and Scope ............................................................................................ 1
   1.1.1. Acknowledgements and Disclaimer ....................................................................... 1
   IRP Flexibility .................................................................................................................... 1
   Legislation ........................................................................................................................... 1
   Accuracy and Disclaimer ................................................................................................. 2
   Sanction ............................................................................................................................. 2
   ARP Review Sub-Committee ............................................................................................ 2
   1.1.2. Scope ...................................................................................................................... 4
   1.1.3. Contents ................................................................................................................. 5
   1.1.4. History .................................................................................................................... 6
   1.1.5. Review Process ....................................................................................................... 7
   1.1.6. 2003 Revisions ....................................................................................................... 8
1.2. Hazard Assessment ............................................................................................................. 11
   1.2.1. Scope ...................................................................................................................... 11
   1.2.2. Hazard Assessment .............................................................................................. 11
   1.2.3. The Blowout Sequence ....................................................................................... 12
   1.2.4. Hazards / Threats .................................................................................................. 13
   1.2.5. Controls / IRP Reference ...................................................................................... 14
1.3. Planning ............................................................................................................................... 23
   1.3.1. Scope ...................................................................................................................... 23
   1.3.2. Project Approval .................................................................................................... 23
       1.3.2.1. IRP Project Approval .................................................................................... 23
   1.3.3. Project Plan ........................................................................................................... 23
       1.3.3.1. IRP Project Plan ......................................................................................... 23
   1.3.4. Emergency Response Plan .................................................................................. 27
       1.3.4.1. IRP Emergency Response Plan ................................................................. 27
   1.3.5. Well Types ............................................................................................................. 30
1.4. Casing Design and Metallurgy .......................................................................................... 33
   1.4.1. Scope ...................................................................................................................... 33
1.4.2. Casing Design: General ................................................................. 33
1.4.3. Casing Collapse Design Specifications........................................ 34
   1.4.3.1. IRP Collapse Design .......................................................... 34
1.4.4. Casing Tension Design Specifications........................................ 34
   1.4.4.1. IRP Casing Tension Design .................................................. 34
1.4.5. Casing Burst Design Specification .......................................... 35
   1.4.5.1. IRP Casing Burst Design .................................................... 35
1.4.6. Environmental Degradation Mechanisms.................................. 36
1.4.7. Casing and Coupling Grades .................................................. 37
   1.4.7.1. IRP Sour Service Casing Grades ......................................... 37
1.4.8. IRP High Temperature Sour Service Casing Grades.................. 37
1.4.9. Additional Casing Specifications ............................................. 38
   1.4.9.1. IRP Additional Casing Specifications .................................. 38
1.4.10. Sulphide Stress Cracking SSC Test Requirements...................... 42
1.4.11. NACE Testing Protocols ....................................................... 42
   1.4.11.1. IRP NACE Testing Protocols ............................................ 42
1.4.12. Sulphide Stress Cracking SSC Test Procedures and Acceptance Requirements ......................................................... 43
   1.4.12.1. IRP Test Procedures and Acceptance Criteria ......................... 43
1.4.13. Manufacturer Pre Qualification ............................................. 45
   1.4.13.1. IRP Manufacturer Pre – Qualification .................................. 45
1.4.15. J55 and K55 Casing: HIC Test Requirements ............................ 46
   1.4.15.1. IRP J55 and K55 Casing: HIC Testing Requirements ................ 46
1.4.16. Electric Resistance – Welded (ERW) Casing ............................ 47
   1.4.16.1. IRP ERW Casing: Pressure Test Requirements ......................... 47
1.4.17. Casing Identification ............................................................ 47
   1.4.17.1. IRP Casing Identification .................................................. 47
1.4.18. Inspection .............................................................................. 47
   1.4.18.1. IRP Inspection of New, Compliant Casing ................................. 47
   1.4.18.2. IRP Non – Compliant Casing: Testing and Inspection Requirements 47
1.4.19. Intermediate Casing .............................................................. 48
1.4.20. Intermediate Casing Setting Depth .......................................... 48
   1.4.20.1. IRP Intermediate Casing: Setting Depth ................................. 48
1.6.4. Flanges, Ring Gasket and Bolting ................................................................. 71
1.6.4.1. IRP Flanges, Ring Gaskets and Bolting Specifications .................... 71
1.6.5. Flexible Steel Hoses ....................................................................................... 73
1.6.5.1. IRP Flexible Steel Hose Specifications .................................................. 73
1.6.6. Pressure Gauges .......................................................................................... 75
1.6.6.1. IRP Standpipe and Casing Pressure Gauges ........................................... 75
1.6.6.2. 1.6.5.2 IRP Choke Panel Pressure Gauges .............................................. 76
1.6.6.3. IRP Pressure Sensor Maintenance and Testing ...................................... 76
1.6.7. Initial Choke Manifold Certification and Documentation ....................... 77
1.6.7.1. IRP Choke Manifold Certification and Documentation ....................... 77
1.6.8. Choke Manifold Shop Servicing and Pressure Testing ........................... 78
1.6.8.1. IRP Choke Manifold Shop Servicing ..................................................... 78
1.6.8.2. IRP Choke Manifold Pressure Testing Procedures ............................. 79
1.7. Mud Gas Separators .......................................................................................... 81
1.7.1. Scope ............................................................................................................. 81
1.7.2. General Requirements .................................................................................. 81
1.7.2.1. IRP Mud – Gas Separator General Requirements ............................. 81
1.7.3. Open Bottom Mud – Gas Separators .......................................................... 82
1.7.3.1. IRP Open Bottom Mud – Gas Separator Specifications ................... 82
1.7.4. Inlet Lines for Mud – Gas Separators (Both Atmospheric and Pressure) ........................................................................................................... 85
1.7.4.1. IRP Inlet Lines for Mud – Gas Separators (Both Atmospheric and Pressure) ........................................................................................................... 85
1.7.5. Vent Lines for Open Bottom Mud – Gas Separators ............................... 86
1.7.5.1. IRP Vent Lines for Open Bottom Mud – Gas Separators .................. 86
1.7.6. Remote Open Bottom Mud – Gas Separators .......................................... 87
1.7.6.1. IRP Remote Open Bottom Mud – Gas Separators .............................. 87
1.7.7. Enclosed Mud–Gas Separators: Design Specifications ............................ 88
1.7.7.1. IRP Enclosed Mud – Gas Separators: Design Specifications ............ 88
1.7.8. Enclosed Mud–Gas Separators: Required Components ......................... 88
1.7.8.1. IRP Enclosed Mud – Gas Separators: Required Components ........... 88
1.7.9. Enclosed Mud – Gas Separators: Fabrication and Operating Guidelines ........................................................................................................... 89
1.7.9.1. IRP Enclosed Mud – Gas Separators: Fabrication and Operating Guidelines ........................................................................................................... 89
1.7.10. Vent Lines for Enclosed Separators ............................................................ 90
1.7.10.1. IRP Vent Lines for Enclosed Separators .............................................. 90
1.7.11. Reference List .............................................................................................. 90
1.8. Drill String Design and Metallurgy ................................................................. 91
  1.8.1. Acknowledgement and Disclaimer .......................................................... 91
  1.8.2. Drill Pipe Grades ....................................................................................... 91
    1.8.2.1. IRP Drill Pipe Grade: Use Specifications ........................................... 92
    1.8.2.2. IRP Drill Pipe Grade: Use Preference ............................................... 92
  1.8.3. Drill String Over Pull Design Considerations ............................................. 92
  1.8.4. Drill Pipe Class / Tensile Rating .............................................................. 92
    1.8.4.1. IRP Drill Pipe Class / Tensile Rating ............................................... 92
  1.8.5. Exposure Control ...................................................................................... 93
    1.8.5.1. IRP Exposure Control ........................................................................ 93
  1.8.6. Hardness Tested API Grade Drill Pipe Specification ..................................... 93
    1.8.6.1. IRP Hardness Tested Grade Drill Pipe Specification: HE, HX, HG ... 93
  1.8.7. SS Grade Drill Pipe Tube Specifications ................................................... 94
    1.8.7.1. IRP Specifications for SS Drill Pipe Tube .......................................... 94
    1.8.7.2. IRP Tensile Property Specifications for SS Drill Pipe Tube ............... 94
    1.8.7.3. IRP Hardness Specifications for SS Drill Pipe Tube ......................... 95
    1.8.7.4. IRP Toughness Specifications for SS Drill Pipe Tube ...................... 95
    1.8.7.5. IRP H₂S Resistance Specifications for SS Drill Pipe Tube ............... 96
    1.8.7.6. IRP Chemistry Specifications for SS Drill Pipe Tube ....................... 96
    1.8.7.7. IRP SS Drill Pipe Tube Transformation and Grain Size .................... 96
    1.8.7.8. IRP Tube / Tool Joint Transition ...................................................... 97
    1.8.7.9. IRP Drill Pipe Identification .............................................................. 97
  1.8.8. SS Grade Tool Joint Specification ............................................................. 97
    1.8.8.1. IRP Specifications for SS Tool Joints .............................................. 97
    1.8.8.2. IRP Tensile Property Specifications for SS Tool Joints ..................... 98
    1.8.8.3. IRP Dimensional and Torsion Specifications for SS Tool Joints .......... 98
    1.8.8.4. Hardness Specifications for SS Tool Joints ...................................... 100
    1.8.8.5. Toughness Specifications for SS Tool Joints ................................... 100
    1.8.8.6. H₂S Resistance Specifications for SS Tool Joints ............................ 100
    1.8.8.7. Chemistry Specifications for SS Tool Joints .................................... 101
    1.8.8.8. SS Tool Joint Transformation and Grain Size .................................. 101
    1.8.8.9. SS Tool Joint Hard banding ............................................................ 101
  1.8.9. Inspection ................................................................................................. 101
    1.8.9.1. IRP Inspection .................................................................................. 101
  1.8.10. Downhole Floats ..................................................................................... 102
    1.8.10.1. IRP Downhole Floats ..................................................................... 102
1.10.4.1. IRP Swab / Surge Pressure: Gel Strengths .............................. 115
1.10.4.2. IRP Rheological Properties .................................................. 116
1.10.5. Alkalinity .............................................................................. 116
  1.10.5.1. IRP Alkalinity: pH Control .................................................. 116
  1.10.5.2. IRP pH Monitoring .............................................................. 116
1.10.6. Equipment and Practices ......................................................... 116
  1.10.6.1. IRP Back-up Drilling Fluid Volumes ...................................... 116
  1.10.6.2. IRP Drilling Fluid Mixing System ........................................ 116
  1.10.6.3. IRP Drilling Fluid Material Inventory .................................... 117
  1.10.6.4. IRP Gas Detector ............................................................... 117
  1.10.6.5. IRP Drilling Fluid Specialist ............................................... 117
  1.10.6.6. IRP Suspension of Drilling Ahead ........................................ 117
1.11. Kick Detection .......................................................................... 119
  1.11.1. Scope .................................................................................. 119
  1.11.2. Drilling Fluid Volume Measurement ........................................ 119
    1.11.2.1. IRP Mud Tank Volume Monitoring System ........................ 119
  1.11.3. Flow line Flow Sensors .......................................................... 120
    1.11.3.1. IRP Flow line Flow Sensors .............................................. 120
  1.11.4. Trip Tanks ........................................................................... 120
    1.11.4.1. IRP Trip Tanks ................................................................. 120
  1.11.5. Monitoring Indirect Indicators ................................................ 121
    1.11.5.1. IRP Electronic Drilling Recorder EDR .................................. 121
    1.11.5.2. IRP Driller’s Instrumentation ............................................ 121
    1.11.5.3. IRP Mud Gas Logging ..................................................... 121
1.12. Wellsite Safety ............................................................................ 123
  1.12.1. Scope .................................................................................. 123
  1.12.2. General Safety Requirements ............................................... 123
    1.12.2.1. IRP Pre-Job Orientation ..................................................... 123
    1.12.2.2. IRP H2S Training ............................................................. 123
    1.12.2.3. IRP Safety Supervision .................................................... 123
    1.12.2.4. IRP Site Access Control ................................................... 124
  1.12.3. H2S Monitoring Equipment .................................................... 124
    1.12.3.1. Continuous H2S Monitoring System .................................. 124
    1.12.3.2. IRP Portable H2S Detection Devices ................................. 125
  1.12.4. Breathing Air Equipment ....................................................... 125
    1.12.4.1. IRP Breathing Air Equipment ........................................... 125
1.13. Wellsite Personnel ................................................................. 126
  1.13.1. Scope ............................................................................. 126
  1.13.2. Responsibilities............................................................. 126
    1.13.2.1. IRP Operator’s Representative ................................. 126
    1.13.2.2. IRP Rig Contractor’s Representative ........................ 126
    1.13.2.3. IRP Shared Responsibility ....................................... 126
  1.13.3. Level of Supervision and Crew Requirements ............. 126
    1.13.3.1. IRP Wellsite Supervisors ........................................ 126
    1.13.3.2. IRP Rig Manager .................................................... 127
    1.13.3.3. IRP Drilling Crew .................................................. 127
  1.13.4. Minimum Qualifications .............................................. 127
    1.13.4.1. IRP Primary Wellsite Supervisor .............................. 127
    1.13.4.2. IRP Second Wellsite Supervisor .............................. 128
    1.13.4.3. IRP Rig Manager .................................................... 128
    1.13.4.4. IRP Drilling Crew .................................................. 129
    1.13.4.5. IRP Safety Specialist .............................................. 129
  1.13.5. Certification and Training Course References ............. 129
  1.14. Practices ........................................................................... 130
    1.14.1. Scope ........................................................................... 130
    1.14.2. IRP Rig Inspection ...................................................... 130
    1.14.3. BOP, Casing and Choke Manifold Pressure Testing 131
      1.14.3.1. IRP BOP Pressure Testing ....................................... 131
      1.14.3.2. IRP Casing Pressure Testing ................................... 131
      1.14.3.3. IRP Choke Manifold Pressure Testing ...................... 131
    1.14.4. BOP Drills .................................................................. 131
      1.14.4.1. IRP BOP Drills ..................................................... 131
    1.14.5. Tripping Practices ...................................................... 132
      1.14.5.1. IRP Trip Supervision ............................................ 132
      1.14.5.2. IRP Hole Fill ....................................................... 132
      1.14.5.3. IRP Trip Record ................................................... 132
      1.14.5.4. IRP Flow Checks .................................................. 133
    1.14.6. Drill Stem Testing ....................................................... 133
    1.14.7. Directional Surveying ................................................ 133
      1.14.7.1. IRP Directional Surveying ..................................... 133
    1.14.8. Coring ........................................................................ 134
1.14.8.1. IRP Coring .................................................................................. 134

1.14.9. **Fishing Operations** ........................................................................ 134
   1.14.9.1. IRP Fishing Operations: Downhole Floats .............................. 134
   1.14.9.3. IRP Fishing Operations: Retrieving Open Hole Logging Tools ..... 135

1.14.10. **Logging** ......................................................................................... 135
   1.14.10.1. IRP Logging ............................................................................. 135

1.14.11. **Casing / Liner Running** ............................................................... 135
   1.14.11.1. IRP Casing / Liner Running .................................................... 135

1.14.12. **Reviews and Safety Meetings** ..................................................... 136
   1.14.12.2. IRP Emergency Response Plan Meeting .................................. 136
   1.14.12.3. IRP Safety / Operational Meetings .......................................... 136

1.14.13. **Wear Bushing** .............................................................................. 136
   1.14.13.1. IRP Wear Bushing ................................................................. 136
LIST OF FIGURES

Figure 1: General Failure Sequence................................................................. 12
Figure 1.2.4.2 Critical Sour Drilling Bowties.................................................. 17
Figure 1. Insufficient Mud Weight To Control Reservoir Pressure............... 17
Figure 2:. Drilling Into Unexpected High Pressure Formation.................... 18
Figure 3:. Loss of Circulation or Returns Resulting In Loss of Hydrostatic Head Which May Cause Well To Flow................................................................. 18
Figure 4: Improper Tripping Practices............................................................. 19
Figure 5. Other Operations: DST, Coring, Fishing, Logging, Casing Running/Cementing ................................................................. 19
Figure 6. Human Error ..................................................................................... 19
Figure KICK: Improper Well Control Procedures........................................ 20
Figure Critical Sour Drilling Bowties.............................................................. 21
Figure 1.4.4 Wellhead vs. Bottomhole Pressure ............................................. 36
Figure: 1.5.1.1 BOP Stack Configuration 1 ................................................... 52
Figure: 1.5.1.2 BOP Stack Configuration 2 ................................................... 53
Figure: 1.5.1.3 BOP Stack Configuration 3 ................................................... 54
Figure: 1.5.1.4 BOP Ram Blanking Tool ...................................................... 55
Figure: 1.5.9.1 Sample of Three Year Test Report ........................................ 64
Figure 1.6.1.1 Choke Manifold Layout......................................................... 70
Figure 1.7.2.1 Open Bottom Mud – Gas Separator; Suggested Configuration83
Figure 1.7.5.1 Open Bottom Mud – Gas Separator: Remote Layout and Sizing ................................................................. 87
Figure 1.8.6.9 Figure: Suggested Drill Pipe Identification ......................... 97
LIST OF TABLES

IRP 1 Review Sub – Committee ..................................................................................... 3
Other Contributors ......................................................................................................... 3
Table 1.1.5.1 ARP 1 vs. IRP 1 .......................................................................................... 6
Table 1.2.4.1 Critical Sour Drilling: Treats, Controls and IRP 1 References...14
Table: 1.4.7.1 Chemical Composition Requirements ..................................................39
Table: 1.4.7.2 Hardness Requirements .........................................................................41
Table: 1.4.16.1 ................................................................................................................47
Table 1.6.3.1 Recommended API Flange Choke/Kill Line Combination ...........72
Table 1.7.2.1 Open Bottom Mud – Gas Separator; Dimensions .........................84
Table 1.7.2.2 Open Bottom Mud – Gas Separator Vessel and Vent Line
Materials .........................................................................................................................85
Table 1.8.5 – API Drill Pipe Hardness Maximum Hardness (Rockwell "C") For HE, HX, and HG Drill Pipe .................................................................................................94
Table 1.8.6.2 SS Drill Pipe Tensile Properties Mpa / Ksi ............................................95
Table 1.8.6.3 SS Drill Pipe Hardness Rockwell "C" (HRC) ............................................95
Table 1.8.6.4 SS Drill Pipe Toughness Minimum Single Valve Charpy "V" ....96
Table 1.8.6.6 Recommended SS Drill Pipe Chemistry Weight per Cent.............96
Table 1.8.7.2 SS Tool Joint Tensile Properties Mpa/Ksi .............................................98
Table 1.8.7.3.1 SS75 Drill Pipe Recommended SS Tool Joint Dimensions and
Resulting Strengths for Typical Connections. .................................................................98
Table 1.8.7.7 Recommended SS Toll Joint Chemistry ...............................................101
1.1. **ACKNOWLEDGEMENTS AND SCOPE**

1.1.1. **ACKNOWLEDGEMENTS AND DISCLAIMER**

This Industry Recommended Practice (IRP) is a set of best practices and guidelines, compiled by knowledgeable and experienced industry and government personnel and is intended to provide the operator with advice regarding Drilling Critical Sour Wells.

The IRP was developed under the auspices of the Drilling and Completions Committee (DACC).

DACC is a joint industry/government committee established to develop safe, efficient, and environmentally suitable operating practices for the Canadian oil and gas industry in the areas of drilling, completions and servicing of wells. The primary effort is the development of IRP’s with priority given to:

- development of new IRPs where non-existent procedures result in issues because of inconsistent operating practices;
- review and revision of outdated IRPs particularly where new technology requires new operating procedures; and
- provide general support to foster development of non-IRP industry operating practices that have current application to a limited number of stakeholders.

**IRP FLEXIBILITY**

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

Throughout this IRP the terms "shall", "must" or "will" are used to indicate firm recommendations. However, acceptable alternatives may be considered provided:

- it is clearly indicated in the planning documentation what recommendations have been modified;
- the alternative provides an equivalent degree of safety and technical integrity; and
- the alternative is reviewed and endorsed by a "qualified technical expert" see IRP 1.3.1 Project Approval.

**LEGISLATION**

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

Every effort has been made to ensure the accuracy and reliability of the data and recommendations contained in the IRP.

However DACC, its subcommittees, and individual contributors make no representation, warranty, or guarantee in connection with the publication or the contents of any IRP recommendation and hereby disclaim liability of responsibility for loss or damage resulting from the use of this IRP, or for any violation of any legislative requirements.

SANCTION

The following organizations have sanctioned (sanction = review and support of the IRP as a compilation of best practices) this document:

- Alberta Employment, Immigration, and Industry
- British Columbia Oil and Gas Commission
- British Columbia Workers Compensation Board (WorkSafeBC)
- Canadian Association of Oilwell Drilling Contractors
- Canadian Association of Petroleum Producers
- Energy Resources Conservation Board (formerly AEUB)
- International Intervention and Coil Tubing Association (Canada)
- Manitoba Energy and Mines
- National Energy Board
- NWT and Nunavut Workers’ Compensation Board
- Petroleum Services Association of Canada
- Saskatchewan Industry and Resources
- Saskatchewan Labour
- Small Explorers and Producers Association of Canada

ARP REVIEW SUB-COMMITTEE

A sub-committee of DACC made up of knowledgeable and experienced industry and government personnel developed this IRP.

Many others also contributed to specific sections of the IRP. While the list is not complete, the following individuals are recognized for their significant contributions
**IRP 1 Review Sub – Committee**

<table>
<thead>
<tr>
<th>Name</th>
<th>Company</th>
<th>Organization Represented</th>
</tr>
</thead>
<tbody>
<tr>
<td>Richard Corvari</td>
<td>Gulf</td>
<td>CAPP</td>
</tr>
<tr>
<td>Dennis High</td>
<td>BP</td>
<td>CAPP</td>
</tr>
<tr>
<td>Mike MacKinnon</td>
<td>Husky Oil</td>
<td>CAPP</td>
</tr>
<tr>
<td>Mike Read (Chair)</td>
<td>Shell</td>
<td>CAPP</td>
</tr>
<tr>
<td>Drew Taylor</td>
<td>Chevron</td>
<td>CAPP</td>
</tr>
<tr>
<td>John Mayall</td>
<td>Alberta Energy Utilities Board</td>
<td></td>
</tr>
<tr>
<td>Warren Randall</td>
<td>Nabors Drilling</td>
<td>CAODC</td>
</tr>
<tr>
<td>Lorne Thompson</td>
<td>Akita Drilling</td>
<td>CAODC</td>
</tr>
<tr>
<td>Darwin Hartley</td>
<td>Precision Drilling</td>
<td>CAODC</td>
</tr>
<tr>
<td>Bob Cunningham</td>
<td>PSC</td>
<td></td>
</tr>
<tr>
<td>Dick Bissett</td>
<td>Bissett Resource Consultants</td>
<td>PSAC</td>
</tr>
<tr>
<td>Chris Knoechel</td>
<td>National Energy Board</td>
<td></td>
</tr>
</tbody>
</table>

**Other Contributors**

<table>
<thead>
<tr>
<th>Name</th>
<th>Company</th>
<th>Organization Represented</th>
</tr>
</thead>
<tbody>
<tr>
<td>Miles Sweep</td>
<td>Chevron</td>
<td>CAPP</td>
</tr>
<tr>
<td>Rick Kirkpatrick</td>
<td>Weatherford</td>
<td>PSAC</td>
</tr>
<tr>
<td>Miguel Stevens</td>
<td>Weatherford</td>
<td>PSAC</td>
</tr>
<tr>
<td>Jean-Paul Saulnier</td>
<td>Energy Rentals</td>
<td>PSAC</td>
</tr>
<tr>
<td>Ramsey Kostandi</td>
<td>Talisman Energy</td>
<td>CAPP</td>
</tr>
<tr>
<td>Karol Szklarz</td>
<td>Shell</td>
<td>CAPP</td>
</tr>
<tr>
<td>Glenn Brown</td>
<td>Grant Pridco</td>
<td>PSAC</td>
</tr>
<tr>
<td>Ed Murphy</td>
<td>Grant Pridco</td>
<td>PSAC</td>
</tr>
<tr>
<td>Scott Biluk</td>
<td>Energy Rentals</td>
<td>PSAC</td>
</tr>
<tr>
<td>Dan Belczewski</td>
<td>Bissett Resource Consultants</td>
<td>PSAC</td>
</tr>
<tr>
<td>Malcolm Hay</td>
<td>Shell</td>
<td>CAPP</td>
</tr>
<tr>
<td>Jerry Thomson</td>
<td>Summit Tubulars</td>
<td>PSAC</td>
</tr>
<tr>
<td>Bruce Williams</td>
<td>Triumph Tubulars</td>
<td>PSAC</td>
</tr>
<tr>
<td>Ron Isinger</td>
<td>Precision Drilling</td>
<td>CAODC</td>
</tr>
<tr>
<td>Darwin Hartley</td>
<td>Precision Drilling</td>
<td>CAODC</td>
</tr>
<tr>
<td>Glen Rabby</td>
<td>Hi-Kalibre Equipment</td>
<td>PSAC</td>
</tr>
<tr>
<td>Dick Molner</td>
<td>Baroid Drilling Fluids</td>
<td>PSAC</td>
</tr>
<tr>
<td>Jim Masikewich</td>
<td>Newpark Drilling Fluids</td>
<td>PSAC</td>
</tr>
</tbody>
</table>
1.1.2. **Scope**

**Goal**
The goal of this IRP is to provide a set of best practices that will prevent a blowout while drilling a critical sour well.

**Application**
This IRP applies to overbalanced drilling of high H₂S (sour) wells using jointed drill strings on conventional drilling or modified service rigs.

It comprises a set of equipment specifications, practices and procedures to address sour drilling issues.

**Critical Sour**
Critical sour refers to wells where the formation fluids are expected to contain hydrogen sulphide (H₂S) in sufficient quantities such that the potential release during a blowout would have significant impact on the public (either high release rate or close proximity to the public).

Critical sour or the equivalent designation is usually explicitly specified by the applicable jurisdictional regulation, such as in Alberta Directive 056: Energy Development Applications and Schedules.

**Good Drilling Practices**
This IRP is meant to supplement the normal good drilling practices applied by competent operators and as required by governmental regulations and guidelines.

It is not meant to be a complete compilation of, or replace, good drilling practices; the focus is on sour drilling issues only.

**Competent and Experienced Drilling Personnel**
This IRP is meant to be a tool for competent, experienced, and knowledgeable drilling personnel.

It is not meant to be used by inexperienced personnel; it makes no attempt to go into enough detail to train inexperienced personnel.

Further discussion of the experience and competencies expected are given in Sections 1.3 Planning and 1.13 Wellsite Personnel.

**Underbalanced Drilling**
This IRP applies to overbalanced drilling only.

For underbalanced drilling, consult IRP 6: Critical Sour Underbalanced Drilling.

**Coil Tubing Drilling**
This IRP applies to jointed pipe drillstring drilling only.
For drilling with continuous tubing (coil tubing), consult IRP 21: Coil Tubing Operations, currently under development. In the absence of IRP 21 consult IRP 6: Critical Sour Underbalanced Drilling.

1.1.3. CONTENTS

The following table briefly describes the contents of each section of the IRP.

A more detailed discussion is given in the Scope subsection at the start of each section.

| 1.1 Acknowledgement and Scope | • Recognizes the organizations and individuals who developed this IRP.  
|                              | • States the disclaimers associated with the IRP  
|                              | • Describes the scope, contents, format, and history of the IRP  
|                              | • Organization represented |
| 1.2 Hazard Assessment         | • Outlines a hazard assessment that was conducted that confirms that all the hazards that could potentially lead to a blowout have been addressed |
| 1.3 Planning                 | • Describes the planning and review practices that should be conducted |
| 1.4 Casing Design and Metallurgy | • Describes the design and material specification for sour casing |
| 1.5 Blowout Preventer Stack  | • Describes the equipment specifications for a sour BOP stack |
| 1.6 Choke Manifold           | • Describes the equipment specifications for a sour choke manifold |
| 1.7 Mud Gas Separators       | • Describes the equipment specifications for sour open bottom and enclosed mud-gas separators. |
| 1.8 Drill String Design and Metallurgy | • Describes the design and material specification for sour, jointed drill strings.  
|                              | • Describes the specifications for current, not fully sour service drill strings.  
|                              | • Describes the specification for new, fully sour service drill strings.  
|                              | • Sets the expectation that after Jan 1, 2002, all new drill strings for critical sour wells will be manufacture to the full sour service specifications and that by Jan 1, 2010, only the full sour service drill strings will be acceptable on critical sour wells. |
| 1.9 Welding                  | • Describes the welding guidelines for sour service equipment |
| 1.10 Drilling Fluids         | • Describes the drilling fluid density, H₂S scavenging, rheological, and acidity requirements.  
|                              | • Outlines additional equipment and practices |
| 1.11 Kick Detection          | • Describes the equipment specifications and practices required for kick detection equipment |
| 1.12 Wellsite Safety         | • Describes the unique safety personnel and equipment required for a critical sour well |
1.13 Wellsite Personnel

- Describes the responsibilities, level of supervision, crew requirements, and minimum qualification for wellsites personnel.

1.14 Practices

- Describes the enhanced practices or restrictions that should be applied to critical sour wells

1.1.4. HISTORY

ARP 1, 1987

ARP 1 Drilling Critical Sour Wells was developed in the mid 1980’s in response to the findings of the Lodgepole Blowout Inquiry Panel (ERCB Decision Report 84-9).

The topics covered by ARP 1 were selected by the Blowout Prevention Review Committee based on the findings of the panel and general industry best practices of the day.

ARP 1 Critical Sour Well Drilling was published in 1987.

ARP 1 Review, 1993

DACC considered revising ARP 1 in 1993 but after a preliminary review, it was felt that there were no significant revisions required.

It should be noted that ARP 1 has proven very successful since there have been no blowouts on any well drilling following ARP 1 (to the best knowledge of the ARP 1 Review Committee).

IRP 1, 2002

DACC again considered revising ARP 1 in 1999 and it was felt that there had been enough improvements in practices that a more rigorous review and revision was worthwhile.

The ARP 1 Review Committee was established in late 1999 to review and revise the existing ARP 1.

The committee finished its work and the revised IRP was sanctioned in January, 2002.

ARP vs. IRP

To facilitate comparing the revisions to the original ARP, the following Table 1.1.5.1 ARP 1 vs IRP 1 summarizes the sections in ARP and the corresponding section in IRP 1.

<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>ARP 1.0 Scope and Contents</td>
<td>IRP 1.1 Acknowledgement, Scope &amp; Introduction</td>
</tr>
<tr>
<td>ARP 2.2 Blowout Preventer Stack</td>
<td>IRP 1.2 Hazard Assessment &amp; Blowout Look Back</td>
</tr>
<tr>
<td>ARP 1.2 Drill Pipe Design And Metallurgy</td>
<td>IRP 1.5 Blowout Preventer Stack</td>
</tr>
<tr>
<td>ARP 1.3 Mud – Gas Separators</td>
<td>IRP 1.6 Choke Manifold</td>
</tr>
<tr>
<td>ARP 1.4 Choke Manifolds</td>
<td>IRP 1.8 Mud – Gas Separators</td>
</tr>
<tr>
<td>ARP 1.5 Auxiliary Equipment</td>
<td>IRP 1.4 Casing Design And Metallurgy</td>
</tr>
<tr>
<td>ARP 1.6 Sour Service Casing</td>
<td></td>
</tr>
</tbody>
</table>
During 2002 and 2004 some minor editing, technical corrections to Section 1.4 Casing Design and Metallurgy and technical corrections to Section 1.9 Welding were identified.

Small task groups addressed the issues, IRP 1 was revised in late 2003 and sanctioned by DACC in January 2004.

The revisions are summarized in Section 1.1.6 2003 Revisions.

IRP Volume 1, 2004

Document was revised with the new IRP style guide and released for industry review. Comments received were not substantive to warrant a review. Document will be reviewed in 2010 if necessary.

1.1.5.  REVIEW PROCESS

DACC IRP Review Process

The sanctioned IRP will have a scheduled review date. Enform will track this date and bring it to DACC’s attention when required. At the scheduled review date, DACC members will be asked if a review is necessary (i.e., change in scope, purpose, technology, practices, etc.).

If at a scheduled review a scope change is necessary, the change must be approved by DACC. If a review is deemed necessary, a new IRP Subcommittee will be created, and the steps of the IRP Development Process followed. If a review is determined not to be necessary, the document will be copyedited by Enform (links, legislative references, etc.) and republished with a new review date.

Notwithstanding, the scheduled review date, a DACC member organization, may request a review of a sanctioned IRP at anytime. To initiate an unscheduled review of a sanctioned IRP, a DACC member organization representative must present a completed IRP Proposal, as described in this document, at a scheduled DACC meeting for consideration.

IRP 1 Review Frequency

DACC will formally review the need to revise IRP 1 every two years.

However, should a DACC member organization request, and with DACC approval, IRP 1 could be reviewed more frequently.
1.1.6. 2003 REVISIONS

Editing and Typos

During the use of IRP 1 through 2002 and, 2003, a few editing and typographical errors were noted and revised.

1.4 Casing Design and Metallurgy

In 2003 a small task group revised this section; the task group consisted of:

- Malcolm Hay, Shell Canada Ltd
- Dan Belczewski, Bissett Resource Consultants Ltd

The following revisions were made to Section 1.4 Casing Design and Metallurgy Table 1.4.7.1

- L80 type 1 column, Manganese line: Add a \((^2\)) beside 1.20; (i.e., change to \(1.20^2\))
- C90 type 1 column, Carbon line: typographical error, (i.e., change to 0.32)
- T95 type 1 column, Carbon line: Add a \((^3\)) beside 0.30; (i.e., change to 0.30\(^3\))
- At the bottom of the table, below
  - 1 Not normally added to this grade: Add:
    - 2 Manganese may be increased to 1.40 % maximum if the sulfur is 0.005 % maximum.
    - 3 Carbon may be increased to 0.35 % maximum and Phosphorus may be increased to 0.015 % maximum if the molybdenum is 0.50 % minimum.

Clause 1.4.11.1

- Fourth paragraph: Change to read as follows:

SSC testing of casing and couplings for critical sour gas service shall be performed in solution A.

Clause 1.4.15.1

Add extra bullets above the existing bullets:

- The following outlines the HIC testing requirements for J55 and K55 casing and couplings.
- There are two protocols:
  1) Testing of all casing and couplings as outlined below.
  2) Pre-qualification of the manufacturer and subsequent testing of selected casing and couplings at the discretion of the purchaser/user. The protocol used for manufacturer pre-qualification (for acceptable SSC resistance) given in clause 1.4.11.1, and the same testing procedure and acceptance criteria as outlined below shall be followed.
- HIC testing is not required on a heat by heat (order) basis if the manufacturer has been pre-qualified.

**Table 1.8.6.3**
- Under Grade Maximum Average – column SS105 change 27.0 to 28.0

**1.9 Welding**
In 2003, section IRP 1.9 Welding was identified as in need of revision.
A small task group revised the section, please review the whole section.
The task group consisted of:
- Chris Chan, ABB Vetco Gray Canada Inc. (leader)
- Malcolm Hay, Shell Canada Ltd
- Dan Belczewski, Bissett Resource Consultants Ltd
1.2. HAZARD ASSESSMENT

1.2.1. Scope

ARP 1 Drilling Critical Sour Wells was developed in the mid 1980's in response to the findings of the Lodgepole Blowout Inquiry Panel (ERCB Decision Report 84-9).

The topics covered by ARP 1 were selected by the Blowout Prevention Review Committee based on the findings of the panel and general industry best practices of the day. However, a rigorous, formal hazard assessment was not conducted.

In preparing the revised IRP 1, a hazard assessment was conducted in order to:

- confirm all hazards that could potentially lead to a blowout on a critical sour well have been identified
- these hazards have been addressed in this revised IRP.

The hazard assessment was conducted using well-established methodologies as described in ISO 17776:2000 “Petroleum and Natural Gas Industries - Offshore Production Installations - Guidelines on Tool and Techniques for Hazard Identification and Risk Assessment.”

Generally the majority of hazards had been addressed in ARP 1. The revised IRP 1 has added a few enhancements, most notably in 1.3 Planning and 1.14 Practices, to address those few that are not covered in ARP 1.

With these enhancements, IRP 1 provides best practices that address all the hazards identified in the hazard assessment.

1.2.2. Hazard Assessment

The hazard assessment was conducted using well-established methodologies as described in ISO 17776:2000 “Petroleum and Natural Gas Industries - Offshore Production Installations - Guidelines on Tool and Techniques for Hazard Identification and Risk Assessment”.

The process steps used were:

- Hazard (Threat) Identification: identified all significant hazards (threats) associated with the drilling of a critical sour well that could lead to a blowout;
- Hazard Control Identification: for each threat, one or several hazard controls were identified which would prevent the threat from escalating to a blowout; and
- IRP 1 Control Review: for each required control, the appropriate section in IRP 1 was identified.

This review identified a few minor areas that the draft IRP 1 had not addressed (e.g., fishing operations). Appropriate enhancements to the IRP were made.

In the view of the ARP 1 Review Committee, the practices outlined in IRP 1 adequately provide the appropriate controls to address all the threats identified.
The whole process and the results are outlined graphically using the "bowtie" protocol at the end of this section.

1.2.3. THE BLOWOUT SEQUENCE

Blowouts do not happen instantaneously, a sequence of events must take place before a release can occur.

Firstly, formation fluids must enter the wellbore. Normally the drilling fluid hydrostatic pressure keeps formation fluids from entering the wellbore.

There are, however, several "threats" (see 1.2.4: Hazards / Threats) that, if not controlled (see 1.2.5 Controls / IRP Reference), could allow formation fluids to enter the wellbore.

Once the formation fluid enters the wellbore, called a “kick”, well control equipment and procedures are used to control and safely dispose of the formation fluid.

If there is a malfunction of the well control equipment, or an error in procedures, an uncontrolled release can occur. If control can quickly be regained using the existing redundant back-up equipment on location, the release is called a “blow”.

**Blow** (as defined by ERCB Directive 056: Energy Development Applications and Schedules) - The uncontrolled flow of wellbore fluids to the atmosphere. The flow can be shut in with the wellhead valve or blowout prevention equipment, or it can be directed to the flare system if the well cannot be shut in indefinitely without exceeding maximum allowable casing pressure (MACP).

If there is a major failure of well control equipment or practices, a full uncontrolled release can occur, called a blowout.

**Blowout** (as defined by ERCB Directive 056: Energy Development Applications and Schedules) - The complete loss of control of the flow of fluids from a well to the atmosphere or the flow of fluids from one underground reservoir to another (an underground blowout). Wellbore fluids are released uncontrolled at or near the wellbore. Well control can only be regained by installing or replacing equipment to shut in or kill the well or by drilling a relief well.

**Figure 1: General Failure Sequence**
1.2.4. **Hazards / Threats**

The following hazards (threats) were identified as the potential causes of a blowout while drilling a critical sour well.

These threats can also have escalation factors,, which could increase the hazard.

The following threats and escalation factors were identified:

1. Insufficient mud weight to control reservoir pressure
2. Drilling into unexpected high pressure formation
3. Loss of circulation or returns resulting in loss of hydrostatic head
   3E1. Losses prior to tripping
   3E2. Plugging drill pipe with lost circulation material
4. Improper tripping practices:
   - 4E1. Swabbing / surging while tripping
   - 4E2. Improper hole fill-up
5. Non "drilling" operations:
   - DST (not allowed in the critical sour zone)
   - Coring
   - Logging
   - Fishing
   - Running and cementing casing
   - 5E1. Insufficient fluid density
6. Human Error (which can exacerbate any threat)

**KICK:** If the controls listed in [1.2.5 Controls / IRP Reference](#) are not effective, a KICK can result. The major threat is improper well control procedures, however there are several escalating factors:

- **KICK:** Improper well control procedures
- **KE1.** Well shut in slow, resulting in a large kick
- **KE2.** Equipment not appropriate for well conditions (size, pressure rating, etc.)
- **KE3.** Material / equipment failure due to sour fluid exposure
- **KE4.** Equipment not maintained, or worn through usage
- **KE5.** Well control procedures not effectively executed
- **KE6.** Flow inside drillpipe
Critical Sour Drilling

- KE7. Problems encountered in open wellbore during kick circulation (lost circulation, formation breakdown, wellbore collapse, etc.)

If the well control procedures are not immediately executed, a short term release of formation fluids can occur, called a blow. Control may be regained through continued application of well control procedures.

A blow could also be caused by failure of a piece of the well control equipment (BOP, Choke Manifold, Mud-Gas Separator, etc). Control may be regained by using the redundancy designed into this equipment (e.g., two chokes, dual mud-gas separators, etc).

If the blow cannot be controlled with the equipment on location, a full uncontrolled release of formation fluids can occur, called a blowout. The blowout would be brought under control by the use of specialized blowout control equipment and practices, or by drilling a relief well.

If a blowout occurs, an emergency response plan (ERP) would be implemented. In fact, the initial stage of the ERP would be implemented during the initial stages of a well control incident.

These THREATS and ESCALATION FACTORS are summarized in Table 1.2.4.1 Critical Sour Drilling: Threats, Controls and IRP 1 References.

### 1.2.5. CONTROLS / IRP REFERENCE

For each threat identified in 1.2.4 Hazards / Threats, specific controls are identified as summarized in Table 1.2.4.1 Critical Sour Drilling: Threats, Controls and IRP 1 References.

For each control identified the corresponding section in IRP 1 which deals with it are also summarized in Table 1.2.4.1 Critical Sour Drilling: Threats, Controls and IRP 1 References.

For each threat, the controls, and IRP references are shown graphically (called "Bowtie Diagrams") in Figure 1.2.4.1 Critical Sour Drilling Bowties.

**Table 1.2.4.1 Critical Sour Drilling: Treats, Controls and IRP 1 References**

<table>
<thead>
<tr>
<th>Threat Description</th>
<th>Control: Design or Practice</th>
<th>IRP 1 Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>E = Escalation Factor</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Insufficient mud weight to control reservoir pressure</td>
<td>Design: drilling program specifies appropriate mud weight</td>
<td>1.3.3 Project Plan</td>
</tr>
<tr>
<td></td>
<td>Practice: follow drilling program</td>
<td>1.13.2 Responsibilities 1.13.3 Level of Supervision and Crew requirements 1.14.12 Reviews and Safety meetings</td>
</tr>
<tr>
<td></td>
<td>Practice: monitor well conditions and increase weight as required</td>
<td>1.10.2 Fluid density 1.11.5 Monitoring Indirect Indicators</td>
</tr>
<tr>
<td>2. Drilling into unexpected high pressure formation</td>
<td>Practice: monitor well conditions and increase weight as required</td>
<td>1.10.2 Fluid density 1.11.5 Monitoring Indirect Indicators</td>
</tr>
<tr>
<td>Threat Description</td>
<td>Control: Design or Practice</td>
<td>IRP 1 Reference</td>
</tr>
<tr>
<td>--------------------------------------------</td>
<td>--------------------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>3. Loss of circulation or returns, resulting in loss of hydrostatic head which may cause well to flow</td>
<td>Design: drilling program specifies appropriate mud weight</td>
<td>1.3.3 Project Plan</td>
</tr>
<tr>
<td>3E1 Losses prior to tripping pipe</td>
<td>Design: Intermediate casing or open hole integrity test isolates possible loss zones</td>
<td>1.3.3 Project Plan&lt;br&gt;1.4.19 Intermediate Casing&lt;br&gt;1.4.20 Intermediate Casing Setting Depth</td>
</tr>
<tr>
<td></td>
<td>Practice: monitor well conditions and adjust mud properties as required</td>
<td>1.10.2 Fluid density&lt;br&gt;1.11.5 Monitoring Indirect Indicators</td>
</tr>
<tr>
<td>3E2 Plugging drillpipe with LC material</td>
<td>Design: drilling program identifies potential problems, identifies actions (e.g. pump out sub)</td>
<td></td>
</tr>
<tr>
<td>4. Improper tripping practices</td>
<td>Design: drilling program specifies hole sizes, BHA, mud weights for proper trip margin</td>
<td>1.3.3 Project Plan</td>
</tr>
<tr>
<td>4E1 Tripping: swabbing/surging while tripping. Rapid tripping increases swabbing</td>
<td>Design: mud properties designed to minimize swabbing</td>
<td>1.10.4 Rheological Properties</td>
</tr>
<tr>
<td>4E2 Tripping: Improper hole fill – up during tripping</td>
<td>Practice: follow tripping procedures, including trip tank monitoring</td>
<td>1.11.4 Trip Tanks&lt;br&gt;1.14.5 Tripping Practices&lt;br&gt;1.13.3 Level of Supervision and Crew Requirements&lt;br&gt;1.13.4 Minimum Qualifications</td>
</tr>
<tr>
<td>5E1 Insufficient Fluid Density</td>
<td>Practice: confirm well conditions prior to starting operations</td>
<td>1.10.2 Fluid density&lt;br&gt;1.11.5 Monitoring Indirect Indicators</td>
</tr>
<tr>
<td>6. Human Error</td>
<td>Design: drilling program developed by qualified personnel and has appropriate scrutiny and approval</td>
<td>1.3.2 Project Approval&lt;br&gt;1.3.3 Project Plan</td>
</tr>
<tr>
<td></td>
<td>Design: supervisors and crew meet competency requirements</td>
<td>1.3.2 Project Approval&lt;br&gt;1.3.3 Project Plan&lt;br&gt;1.13.4 Minimum Qualifications&lt;br&gt;1.13.5 Certification and Training Course References</td>
</tr>
<tr>
<td>Kick: improper well control procedures</td>
<td>Practice: effective well control procedures: shut in well, circulate out kick,</td>
<td>1.13.2 Responsibilities&lt;br&gt;1.13.3 Level of Supervision and Crew Requirements</td>
</tr>
<tr>
<td>Threat Description</td>
<td>Control:</td>
<td>IRP 1 Reference</td>
</tr>
<tr>
<td>-----------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| **E = Escalation Factor**                                                          | regain well control                                                      | 1.13.4 Minimum Qualifications
|                                                                                  |                                                                          | 1.13.5 Certification and Training Course References
|                                                                                  |                                                                          | 1.14.4 BOP Drills                                                             |
| KE1 Well shut in procedures slow > large kick                                     | Practice: well conditions monitored                                     | 1.11 Kick Detection Equipment                                                  |
| KE2 Equipment not appropriate for well conditions (size, pressure rating, etc.)   | Design: drilling program identifies appropriate size & pressure requirements | 1.3.3 Project Plan                                                            |
| KE3 Material / Equipment failure due to sour fluid exposure                        | Design: equipment meets sour service requirements                         | 1.4 Casing and Metallurgy
|                                                                                  |                                                                          | 1.5 Blowout Preventer (BOP) Stack                                              |
|                                                                                  |                                                                          | 1.6 Choke Manifold                                                            |
|                                                                                  |                                                                          | 1.7 Mud Gas Separators                                                         |
|                                                                                  |                                                                          | 1.8 Drill String Design and Metallurgy                                         |
|                                                                                  |                                                                          | 1.9 Welding                                                                    |
| KE4 Equipment not maintained, or worn through usage                                | Practice: equipment in good working order: regular inspections and tests  | 1.14.2 IRP Rig Inspection
|                                                                                  |                                                                          | 1.14.3 BOP, Casing and Choke Manifold Pressure Testing                        |
| KE5 Well Control procedures not effectively executed                              | Practice: effective Kick detection, rapid shut in                        | 1.13.4 Minimum Qualifications
|                                                                                  |                                                                          | 1.14.4 BOP Drills                                                             |
| KE6 Flow inside drillpipe                                                         | Design: float valve, Stabbing valve to prevent flow up drill steam       | 1.8.10 Downhole Floats                                                        |
|                                                                                  |                                                                          | 1.8.11 Upper Kelly Cocks, Lower Kelly Cocks and Stabbing Valves               |
| KE7 Problems encountered in open wellbore during kick circulation: (lost circulation, formation breakdown, wellbore collapse, etc.) | Design: intermediate casing minimizes open hole                           | 1.4.19 Intermediate Casing
|                                                                                  |                                                                          | 1.4.20.1 IRP Intermediate Casing: Setting Depth and 1.4.20.2 IRP Intermediate Casing: Exemption |
|                                                                                  |                                                                          | 1.5 Blowout Preventer (BOP) Stack                                              |
|                                                                                  |                                                                          | 1.6 Choke Manifold                                                            |
|                                                                                  |                                                                          | 1.7 Mud Gas Separators                                                         |
| BLOW: a short term uncontrolled release of formation fluid to the atmosphere that was brought under control by the well control equipment on location | Practice: shut in well with redundant equipment, circulate out kick, regain well control | 1.13.2 Responsibilities
|                                                                                  |                                                                          | 1.13.3 Level of Supervision and Crew Requirements                            |
|                                                                                  |                                                                          | 1.13.4 Minimum Qualifications
|                                                                                  |                                                                          | 1.13.5 Certification and Training Course References                          |
|                                                                                  |                                                                          | 1.14.4 BOP Drills                                                             |
|                                                                                  | Design: redundant well control equipment                                  | 1.3.4 Emergency Response Plan
|                                                                                  |                                                                          | 1.14.12 Reviews and Safety meetings                                           |

| BLOWOUT: a blow that existing equipment cannot control and additional equipment or relief well used to regain control | Practice: Implement ERP | 1.3.4 Emergency Response Plan
|                                                                                                                        |                                                                          | 1.14.12 Reviews and Safety meetings                                           |
Figure 1.2.4.2 Critical Sour Drilling Bowties

Note: Overall View, Details Follow

Threat(s)

Figure 1. Insufficient Mud Weight To Control Reservoir Pressure

1. Insufficient weight to control reservoir

Design: Drilling program specifies appropriate mud weight

Practice: Follow drilling program

Practice: Monitor well conditions and increase weight as required

KICK: Improper well control

1.3.3 Project Plan

1.13.2 Responsibilities
1.13.3 Level of Supervision and Crew Requirements
1.14.12 Reviews and Safety Meetings

1.10.2 Fluid density
1.11.5 Monitoring Indirect Indicators

Redundant Equipment & Procedures

Controls Fail

Proper Well Control Procedures

KICK
Figure 2: Drilling Into Unexpected High Pressure Formation

2. Drilling into unexpected high pressure formation

Practice: Monitor well conditions and increase weight as required

KICK: Improper well control procedures

1.10.2 Fluid Density
1.11.5 Monitoring Indirect Indicators

Figure 3: Loss of Circulation or Returns Resulting In Loss of Hydrostatic Head Which May Cause Well To Flow

3. Loss of circulation or returns resulting in loss of hydrostatic head which may cause well to flow

Design: Drilling program specifies appropriate mud weight

Design: Intermediate casing or open hole integrity test isolates possible loss zones

Practice: Monitor well conditions and increase weight as required

KICK: Improper well control procedures

1.3.3 Project Plan
1.4.19 Intermediate Casing
1.14.18 Intermediate Casing setting Depth

Design: Drilling program identifies potential problems, identifies actions (e.g. Pump out sub)

1.3.3 Project Plan
1.10.2 Fluid density
1.11.5 Monitoring Indirect Indicators
Figure 4: Improper Tripping Practices

4. Improper tripping practices

4E1. Tripping: Swabbing/surging while tripping

Design: Drilling program specifies hole sizes, BHA, mud weights for proper trip margin

1.3.3 Project Plan

Design: Mud properties designed to minimize swabbing

1.10.4 Rheological Properties

Practice: Follow tripping procedures, including trip tank monitoring

KICK: Improper well control procedures

4E2. Tripping: Improper hole fill-up during tripping

Figure 5. Other Operations: DST, Coring, Fishing, Logging, Casing Running/Cementing

5. Other Operations: DST, Coring, Fishing, Logging, Casing Running/Cementing

5E1. Insufficient Fluid Density

Practice: Follow IRP 1 Procedures

KICK: Improper well control procedures

1.14.5 Drillstem Testing not allowed in sour zone
1.14.7 Coring
1.14.8 Fishing Operations
1.14.9 Logging
1.14.10 Casing/Liner Running

Figure 6. Human Error

6. Human Error

Design: Drilling program developed by qualified personnel and has appropriate scrutiny and approval

1.3.1 Project approval
1.3.2 Project Plan

Design: Supervisors and crew meet competency requirements

1.13.1 Responsibilities
1.13.2 Level of Supervision & Crew Requirements
1.13.3 Minimum Qualifications
1.13.4 Certification & Training

Practice: BOP drills to improve competency

1.14.3 BOP Drills
1.13.5 Reviews and Safety Meetings

KICK: Improper well control procedures
Figure KICK: Improper Well Control Procedures

KE1: Well Shut in procedures slow > large kick

Practice: Effective well control procedures: shut in well, circulate out kick, regain well control

KE2: Equipment not appropriate for well conditions (size, pressure rating, etc)

Design: Drilling program identifies appropriate size & pressure requirements

KE3: Material / Equipment failure due to sour fluid exposure

Design: Equipment meets sour service requirements

KE4: Equipment not maintained, or worn through usage

Practice: Equipment in good working order: regular inspections and tests

KE5: Well Control procedures not effectively executed

Practice: Effective well control procedures: shut in well, circulate out kick, regain well control

KE6: Flow inside drill pipe

Design: Float valve, stabbing valve to prevent flow up drill string

KE7: Problems encountered in open wellbore during kick circulation

Design: Intermediate casing minimizes open hole

BLOW: a short term uncontrolled release of formation fluid to the atmosphere that was brought under control by the well control equipment on location

KE1. Well Shut in procedures slow > large kick

KE2. Equipment not appropriate for well conditions (size, pressure rating, etc)

Design: Drilling program identifies appropriate size & pressure requirements

KE3. Material / Equipment failure due to sour fluid exposure

Design: Equipment meets sour service requirements

KE4. Equipment not maintained, or worn through usage

Practice: Equipment in good working order: regular inspections and tests

KE5. Well Control procedures not effectively executed

Practice: Effective well control procedures: shut in well, circulate out kick, regain well control

KE6. Flow inside drill pipe

Design: Float valve, stabbing valve to prevent flow up drill string

KE7. Problems encountered in open wellbore during kick circulation

Design: Intermediate casing minimizes open hole

BLOW: a short term uncontrolled release of formation fluid to the atmosphere that was brought under control by the well control equipment on location

1.1.3.1 Responsibilities
1.13.2 Level of Supervision & Crew Requirements
1.13.3 Minimum Qualifications
1.13.4 Certification & Training
1.14.3 BOP Drills

1.1.11 KICK DETECTION EQUIPMENT

KE1. Well Shut in procedures slow > large kick

Practice: Effective well control procedures: shut in well, circulate out kick, regain well control

KE2. Equipment not appropriate for well conditions (size, pressure rating, etc)

Design: Drilling program identifies appropriate size & pressure requirements

KE3. Material / Equipment failure due to sour fluid exposure

Design: Equipment meets sour service requirements

KE4. Equipment not maintained, or worn through usage

Practice: Equipment in good working order: regular inspections and tests

KE5. Well Control procedures not effectively executed

Practice: Effective well control procedures: shut in well, circulate out kick, regain well control

KE6. Flow inside drill pipe

Design: Float valve, stabbing valve to prevent flow up drill string

KE7. Problems encountered in open wellbore during kick circulation

Design: Intermediate casing minimizes open hole

BLOW: a short term uncontrolled release of formation fluid to the atmosphere that was brought under control by the well control equipment on location

SOUR: a long term uncontrolled release of formation fluid to the atmosphere that was not brought under control by the well control equipment on location

Critical Sour Drilling
**Figure Critical Sour Drilling Bowties**

**Blow**: a short term uncontrolled release of formation fluid to the atmosphere that was brought under control by the well control equipment on location.

**Blowout**: a blow that existing equipment cannot control and additional equipment or a relief well used to regain control.
1.3. **PLANNING**

1.3.1. **SCOPE**

The purpose of the planning section is to outline the planning and review practices that should be conducted to ensure technical and safety integrity of a critical sour drilling project.

1.3.2. **PROJECT APPROVAL**

1.3.2.1. **IRP Project Approval**

The overall project plan and application to the appropriate regulator to undertake the drilling of a critical sour well will be developed and signed by a qualified technical expert authorized by the operator.

That representative, by their signature will be confirming that all the requirements of this IRP have been addressed in the plan and that the terms of the project plan will be applied during the execution of the plan.

The signature will also confirm that appropriate input from qualified technical experts has been obtained where required and that the qualifications of the technical experts are valid.

**Flexibility and Technical Judgment**

Due to the complexity of a critical sour drilling project, and to allow for continuous improvement regarding safety and operational efficiency, IRP 1 recommendations are meant to allow flexibility.

Therefore, competent technical judgment must be used concurrently with these recommendations.

It is the operator’s responsibility to ensure the required technical judgment has been used to develop the project plan and will be used during the execution of the project.

**Qualified Technical Expert**

IRP 1 allows flexibility in practices in several instances provided a qualified technical expert relative to the practice / technology has approved the options in question.

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.).

The operator will be able to demonstrate this upon audit.

1.3.3. **PROJECT PLAN**

1.3.3.1. **IRP Project Plan**

A drilling project plan (drilling program) must be developed which will address the requirements as outlined below (based on ERCB Directive 056: Energy Development Applications and Schedules).
**Plan Objectives**

The purpose of the project plan is to document the well design, equipment, and practices that will be used during the project execution.

A key use of the plan is to provide directions to the wellsite personnel; the plan must have enough detail to allow the wellsite personnel to clearly understand the hazards and required actions.

For those areas of common practice with no variance from normal operations, a brief overview can be provided with references to more detailed discussion, (e.g., this IRP)

**Project Plan Contents**

**Geological Setting / H₂S Release Rate**

There should be a discussion regarding the expected geological zones, including identification of sour and critical sour zones.

An offset well data search to a minimum 5 km radius from the subject well should be conducted.

Data from relevant wells should be reviewed to get a clear understanding of potential problems and design issues:

Relevant = most current, analogous geology, similar depth

Examination of the wells at greater distances may be required to ensure all relevant information is reviewed.

Offset well data (well files, logs, and drilling event data) can be obtained from governmental agencies, as well as commercial services.

Some information respecting wells may be confidential for a period of time after an offset well has been drilled. However, for critical sour wells, an informal discussion is recommended with the licensee of a nearby well respecting any potential drilling problems.

This data should be summarized and referenced on an Offset Well Map that indicates all offset analogue wells.

Calculations used to determine H₂S release rate calculations should follow:

- “H₂S Release Rate Assessment Guidelines and Audit Forms”, CAPP, 1999
- A summary of this assessment should be included in the project plan

**Problems and Well Design**

Offset well information should be reviewed and a summary outlining the hole problems expected, solutions and reasons for selecting casing setting depths should be included in the project plan.

**Emergency Response Plan (ERP) Setting**

An overview of the ERP with regard to the degree of difficulty in implementing the plan (see 1.3.4 Emergency Response Plan)
Well Type

A discussion of the well type based on (see 1.3.5 Well Types):
  o complexity of the well (geology and well design);
  o the potential impact to the public (magnitude of \(\text{H}_2\text{S}\) release rate and proximity to public); and
  o the ease or difficulty of evacuation (number of affected public and evacuation issues).

Casing Design (see 1.4 Casing Design and Metallurgy)

Casing details: casing depth, grade, weight, size: for surface, intermediate and production casing.

Details of the surface-casing bowl.

Details of casing design and sour service suitability of the casing grades. If grades other than L-80 are proposed, details on chemistry specifications must be reviewed and documented.

Casing design for horizontally drilled wells must also address the additional stresses and loads.

Blowout Prevention Equipment (see 1.5 Blowout Preventer Stack, 1.6 Choke Manifold, 1.7 Mud Gas Separators)

BOP stack configuration used and its pressure rating.

If blind shear rams were not planned, the reasons must be included.

Choke manifold configuration and pressure rating.

The number of mud-gas separators planned. If only one mud-gas separator was planned, include the reasons.

Drill String (see 1.8 Drill String Design and Metallurgy)

There should be a summary of the grade, type (new/used), and class of drill pipe.

If grade is other than sour service drill pipe as defined in IRP 1.8 Drill String Design and Metallurgy, include:
  o A discussion of sour-service suitability.
  o Drill pipe design of both the grade planned and Grade E, including a comparison of overpull tensile margins at the surface or other design factors affecting the choice of grade.
  o The \(\text{H}_2\text{S}\) exposure control plan (see 1.10 Drilling Fluids, 1.8.5 Exposure Control)

Drilling Fluids (see 1.10 Drilling Fluids)
Provide a summary of the type, the density, the pH level, the amount of weight material on site.

If the system will be pretreated with an H₂S scavenger, and the type of additional drilling fluid that will be kept on site.

Kick Detection (see 1.11 Kick Detection)

Provide a summary of the kick detection and monitoring equipment that will be used.

Wellsite Safety (see 1.12 Wellsite Safety)

Provide a summary of the wellsite safety equipment and procedures that will be used.

Inspection and Equipment Testing Procedures (see 1.14 Practices)

Provide a description of the inspection and testing procedures designed to ensure that all equipment is fully operational prior to the well reaching the critical depth and procedures to ensure that a state of readiness is maintained.

Wellsite Personnel (see 1.13 Wellsite Personnel)

Provide a description of the wellsite personnel and their qualifications.

Practices (see 1.14 Practices)

Provide a discussion of any special practices, for example:

- Tripping
- Coring
- Directional surveys

Blowout Insurance

Provide a statement that the company (including working interest owners) is self-insured, or other proof of insurance must be filed and available for audit.

Companies licensing a critical sour well must either be self-insured to cover the costs of a blowout or must obtain significant liability insurance.

Insurance amounts depend on the well depth and must include provision for pollution and seepage, evacuation expense, underground blowout, and care/custody, and control.

In addition, if the well is a "joint venture," the company must either hold insurance for 100 % of the working interest, or have a copy of insurance policies for the interest of each partner.
Critical Sour Drilling

Wellbore Diagram

The information compiled in the project plan should be summarized on a Wellbore Diagram, including:

- Geological setting, formation expected
- H₂S Release Rates
- Hole problems
- Casing design
- Formation pressure or equivalent mud density or formation pressure gradient

A copy of the Wellbore Diagram should be reviewed with rig crews and posted in the doghouse (see 1.14 Practices).

Copies

Prior to drilling any critical well, copies of the plan must be:

- on site during drilling operations;
- filed (one copy) with the appropriate governmental field office (as required) for use during a site inspection; and available for audit of the application for well license, or filed with the well license application if the application is to be heard at a public hearing.

1.3.4. Emergency Response Plan

1.3.4.1. IRP Emergency Response Plan

A site specific Emergency Response Plan must be developed for each critical sour well. This plan must be approved by the appropriate governmental agency responsible for public safety.

Emergency Response Plan Overview

As a minimum, and while recognizing that any applicable regulations must be adhered to and any uniqueness in those regulations taken into account, the Alberta ERCB Directive 71 Emergency Preparedness and Response Requirements for the Petroleum Industry should be used as a standard for developing an ERP for drilling a critical sour well.

Each plan must consider site-specific circumstances. Variations in the plans can be expected based on factors such as the geological prognosis of the well, population density and distribution, and the consequences of a blowout.

Public input from local residents, municipal administrators and first responders is an integral part of preparing an effective emergency response plan. In some instances it may be necessary to hold public meetings to obtain this input.

The appropriate jurisdictional agency approving the ERP addresses specific requirements for emergency planning zone (EPZ), public consultation, etc.
Emergency Planning Zone

The appropriate emergency planning zone (EPZ) must be carefully selected and must be adequate to ensure the safety of the public near the well.

The size and shape of the zone must reflect the maximum drilling H₂S release rate but must also have regard for the local terrain, density of population in the area, and access and egress routes through the EPZ.

Consult the appropriate jurisdictional agency approving the ERP for specific requirements.

Emergency Response Plan Contents

(The contents listed below are basic contents only, and there needs to be a reference to the minimum standard for provisional of detailed plan content.)

1) Summary

This section is a summary of the key facts about the proposed well and the emergency response plan, and should be consistent with any information found in the respective resident information package.

2) Emergency Definition and Action

This section describes the various circumstances that could lead to a sour gas release and the intended response.

It defines the various stages of an emergency and describes the action for each stage.

In addition, it describes the responsibility of company, agency and response personnel involved in any stage of the emergency.

Other considerations for action planning include prioritization of response and after the emergency recovery procedures.

This section would also describe the emergency organization and incident management system to be used.

3) Public Protection Measures

- Evacuation Procedures

This section defines the criteria to be used to initiate an evacuation and describes how the evacuation would be carried out.

Details respecting the air quality monitoring program and communication procedures are also addressed.

For critical sour wells where the emergency planning zone includes all or a portion of a densely populated area such as an acreage development or an urban centre, additional stationary and mobile air quality monitoring units are required during the drilling of the potential sour zones.
• Shelter in Place
This section defines the criteria to be used when sheltering indoors is a viable public protection measure, instead of or along with evacuation of the public. Shelter in place instructions need to be included in the ERP.

• Ignition Criteria
This section defines the ignition criteria and circumstances leading to the deliberate ignition of the well.
There must be clear and specific plans in place to ignite an uncontrolled flow of sour gas, consistent with the ignition criteria, which needs to take into account unevacuated public, H₂S concentrations, effectiveness of monitoring and any lack of control over the release.

4) Resident Information Package
This section includes a copy of the Resident Information Package that is to be provided to residents within the emergency planning zone. The package provides a brief summary of the proposed well and operator, a summary of evacuation and ignition procedures, emergency telephone numbers and a description of the hazards of H₂S and sulphur dioxide.

5) Contact Information
This section provides a listing of the residents, company personnel, affected agencies and response organizations and suppliers that would be contacted in the event of a sour gas release.

6) Maps
This section includes the maps necessary to show:

• the selected emergency planning zone and the surface developments, roads, topographical features and any other criteria established by the jurisdictional legislation, within the zone

• other zones to be included on the map are:
  o emergency awareness zone
  o immediate hazard and response zones

7) Copies
A copy of the approved emergency response plan must be on site during drilling operations, prior to drilling out the surface casing, and during all completion or servicing operations of designated critical sour wells.
Copies of the approved emergency response plan must be sent to the appropriate jurisdictional agencies and response providers as noted in the jurisdictional legislation and as agreed to by the affected parties.
8) Appendices

Each plan should include all relevant information that could possibly be required to prepare for, and respond to, a sour gas emergency. Items to consider are:

- glossary of terms
- ERP application documents
- information on H$_2$S exposure
- emergency level designation criteria
- evacuation criteria
- shelter in place criteria and instructions
- ignition criteria
- communication and notification requirements
- any necessary forms required to be used during an emergency event

1.3.5. **Well Types**

**General**

These recommended practices allow some flexibility based on the following three criteria:

- complexity of the well (geology and well design);
- the potential impact to the public (magnitude of the H$_2$S release rate and proximity to public); and
- the simplicity or difficulty of evacuation (number of affected public and evacuation issues)

Depending on the combination of these criteria, certain options may be used:

- The options are discussed in the appropriate IRP section
- The options must be discussed in the project plan
- The options concern, for example:
  - Casing setting depth (see 1.4.20 Intermediate Casing Setting Depth)
  - Shear Blind Rams (see 1.5.3 Shear Blind Rams)
- Mud-Gas Separators (see 1.7.2.1 IRP Mud – Gas Separator General Requirements)

**Low Complexity Well**

A well is considered low complexity if it is in a known area with no drilling problems, based on the geological prognosis of the proposed well:

- The well must be in a known and established field area that offsets existing development.
• A summary of offset wells confirms that no significant lost circulation problems or other adverse drilling conditions are expected.

• A summary of drill stem test pressures, mud densities, or other information verifies normal formation pressures are expected.

Typically this would mean a development well may be a low complexity well, while an exploration well would not.

A low complexity well would have less uncertainty and therefore would have lower risk of a problem due to well conditions.

**Low Impact Well**

A well would have low potential impact to the public if it has a low H₂S release rate and/or is not in close proximity to public:

• The maximum potential H₂S release rate is less than 3 m³/s

• The calculated EPZ does not intersect an urban centre,

**Simple ERP Well**

A well would have a simple ERP if it would be relatively easy to evacuate the EPZ:

• The calculated EPZ encompasses less than 10 occupied dwellings.

• There is no communication, evacuation route, terrain, or weather issues.
1.4. Casing Design and Metallurgy

1.4.1. Scope

Casing Design

Basic casing design (burst, collapse, and tension) should follow the appropriate regulatory requirements.

An additional design factor is included for burst design to ensure the casing would not come close to its specified minimum yield stress (SMYS) and thus be more susceptible to Sulphide Stress Cracking (SSC).

Recommended practice for intermediate casing is also provided.

Casing Metallurgy

Intermediate and production casing must be suitable for sour service.

Specific casing grades are specified based on API grades with additional chemistry and testing requirements. This essentially means that the manufacturer will need to provide proprietary grades of casing and couplings.

Adherence to this IRP should ensure that casing and couplings with adequate resistance to:

- Sulphide Stress Cracking (SSC),
- Hydrogen-Induced Cracking (HIC), and
- Stress-Oriented Hydrogen-Induced Cracking (SOHIC)
- (under normal stressing and environmental exposure situations).

Other grades of casing may be used provided they are approved by a qualified technical expert adequately familiar with the metallurgical and testing requirements for sour service casing and couplings in order to avoid the identified environmental degradation mechanisms (SSC, HIC and SOHIC).

This IRP is applicable to carbon and low alloy steel casing and coupling grades. It does not address corrosion or the use of corrosion-resistant alloys. Corrosion and its control by chemical additives or by other means, and the specification of corrosion-resistant alloys, are outside the scope of this IRP.

1.4.2. Casing Design: General

General

The following casing design recommended practices apply to the last casing string set prior to the well becoming critical (typically intermediate, but possible surface casing) and production casing.

They apply to both new casing and existing casing in re-entry wells. For a re-entry well, a casing wear evaluation must be conducted and the design checked against these recommendations.
All applicable intermediate and production casing must meet the metallurgical specifications in this IRP.

**Note**  As of January, 2002, IRP 1.4.5.1 IRP Casing Burst Design is being reviewed for possible inclusion of alternate casing design criteria.

### 1.4.3. Casing Collapse Design Specifications

#### 1.4.3.1. IRP Collapse Design

- No internal pressure.
- For re-entry wells, the assessment is required from:
  - surface to 150 m below the confirmed cement top or,
  - surface to 1,000 m.
  - whichever is the greater.
- Collapse resistance is reduced by tensile load in accordance with the latest edition of API Bull 5C3, “Formulas and Calculations for Casing, Tubing, Drill Pipe and Line Pipe Properties.”
- The ERCB publication Directive 015: Effect of Tensile Loading on Casing Collapse and equations in API Bull 5C3 may be used to determine the collapse resistance.
- The design check should be based on an external fluid gradient of the original mud density prior to running the casing. Approval may be granted for less (minimum 10 kPa/m) provided the actual fluid gradient does not exceed design gradient.
- Collapse strength is based on remaining wall thickness.
- Safety Factor = 1.0

### 1.4.4. Casing Tension Design Specifications

#### 1.4.4.1. IRP Casing Tension Design

- Buoyant effect is neglected.
- For re-entry wells, the assessment is required only from:
  - surface to 150 m below the confirmed cement top
  - surface to 1,000 m
  - whichever is the greater.
- Yield strength of the casing wall is used if this is less than joint strength.
- Tensile strength is adjusted to remaining wall thickness.
- Safety Factor: New = 1.6
- Safety Factor: Re-entry = 1.2
The safety factor has been reduced from 1.6 to 1.2 since an existing casing will not experience running or cementing loads anticipated in the original design.

1.4.5. **CASING BURST DESIGN SPECIFICATION**

1.4.5.1. **IRP Casing Burst Design**

Production Casing Internal Pressure = 85% of original maximum producing formation pressure or, if for a re-entry well, with the review and approval by a qualified technical expert, 85% of current maximum producing formation pressure.

- The 85% factor is based on the data in Figure 1.4.4.1 Wellhead vs. Bottomhole Pressure.
- This data shows that for all normally pressured wells, the wellhead pressure is less than 85% of bottomhole pressure.
- The four wells above the 85% line represent shallow, highly overpressured reservoirs which would not be applicable for Critical Sour wells.

Intermediate Casing Internal Pressure = the same as for the production casing = 85% of maximum producing formation pressure.

Internal pressure is free to act over the full length of casing string.

No allowance is made for external pressure.

For re-entry wells, the burst rating of the casing = \((1 - \text{accuracy of wall thickness log}) \times 2(\text{Specified Minimum Yield Strength}) \times (\text{current wall thickness} / \text{casing O. D.})\)

**Safety Factor = 1.25**

- For Critical Sour Wells, the safety factor has been increased from the standard 1 to 1.25.
- This will ensure that even under maximum load the casing would be at less than 80% of its burst rating and so would not come close to its specified minimum yield stress.
- The lower stress load would greatly reduce the susceptibility to Sulphide Stress Cracking (SSC).
- A lower safety factor may be considered, provided that:
  - In addition to meeting the NACE TM0177-96 Method D (double cantilever beam specimen) sulphide stress cracking test requirements in this document, the casing material must also be tested using Method A (uniaxial tension specimen) at a stress level at least 10% higher than the intended loading levels.
  - For example, if the safety factor is only 1.15, then the required test stress level must be \(1/1.15 + 10\%\), or in this case, 96% SMYS.
Furthermore, for safety factors in burst less than 1.25, sulphide stress crack testing must be conducted on every heat of Grade L80 Type 1, in addition to Grade C90 Type 1 and T95 Type 1.

**Figure 1.4.4 Wellhead vs. Bottomhole Pressure**

---

### 1.4.6. **Environmental Degradation Mechanisms**

Sour gas contains hydrogen sulphide (H₂S) and carbon dioxide (CO₂) at various partial pressures and ratios.

These gases make any aqueous environment present acidic and potentially corrosive. In addition, the presence of hydrogen sulphide may make the casing and coupling materials susceptible to environmental embrittlement mechanisms.

This IRP addresses three environmental degradation mechanisms that may be active when the casing and couplings are exposed to sour gas:

- **Sulphide Stress Cracking (SSC),** which may be active in all casing and coupling grades listed.

- **Hydrogen-Induced Cracking (HIC),** which may be active in J55 and K55, manufactured by either the seamless or the electric resistance welding process. Quenched and tempered microstructures typically have high resistance to HIC. Tensile stress is not necessary for the initiation and growth of HIC.
• Stress-Oriented Hydrogen-Induced Cracking (SOHIC), which also may be active in J55 and K55 manufactured by either the seamless or the electric resistance welding process.

Quenched and tempered microstructures typically have high resistance to SOHIC. SOHIC appears to be a combination of HIC and SSC.

SSC may occur very quickly (minutes to hours) upon exposure of susceptible casing and couplings to sour gas, depending on the level of tensile stress (residual and operating), the temperature, acidity (pH) of the aqueous environment, partial pressure of H₂S, and the inherent resistance of the material. SOHIC and HIC are more time-dependent mechanisms, though failure by SOHIC may occur within two days in highly susceptible material.

1.4.7. Casing and Coupling Grades
API Grades

Note As of January, 2002 IRP 1.4.6 is being reviewed for the possible inclusion of Grade 110 casing

1.4.7.1. IRP Sour Service Casing Grades
Intermediate and production casing must be suitable for sour service.

The following grades listed in API 5CT are intended for sour gas exposure and are suitable for use in critical sour gas wells at any temperature, provided that the additional requirements identified in this IRP have been applied:

• J55 and K55 (seamless or electric resistance-welded)
• L80 Type 1 (seamless or electric resistance-welded)
• C90 Type 1 (seamless)
• T95 Type 1 (seamless)

1.4.8. IRP High Temperature Sour Service Casing Grades
The following non-sour service-rated grades are suitable for use in critical sour gas wells provided that their operating temperature remains forever above the minimum stated (per NACE International Standard MR0175 latest edition, “Material Requirements – Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment”):

• Proprietary seamless, quenched and tempered grades with 758 MPa (110 ksi) maximum yield strength: 65 °C and above.
• P110 (seamless process only, maximum permitted sulphur 0.010 %, maximum permitted phosphorus 0.020 %): 80 °C and above.
• Proprietary seamless, quenched and tempered grades to 965 MPa (140 ksi) maximum yield strength: 80 °C and above.
• Q125 Type 1 (Cr-Mo chemistry, seamless process, quenched and tempered, 1,034 MPa (150 ksi) maximum yield strength only): 107 °C and above.

Operating temperature should be determined; the following should be considered:

• An open-hole temperature log run is suggested across the uppermost proposed location of the non-sour service rated casing.

• Due to potential cooling associated with gas production, those casing joints at and below the production packer should be sour service-rated grades.

• The presence of underground aquifers and their potential effect on the temperature of the casing and couplings shall be taken into account when specifying non-sour service-rated casing and couplings.

1.4.9. **ADDITIONAL CASING SPECIFICATIONS**

1.4.9.1. **IRP Additional Casing Specifications**

The requirements identified below must be applied in addition to those of specification of API 5CT.

This IRP is intended to supplement the requirements of API 5CT. In all cases, API 5CT is the basic specification to which the following enhancements are recommended.

**Casing Chemical Composition Specifications**

Casing and couplings made from steel meeting the minimum chemical composition requirements of each grade listed in API 5CT and this IRP will not necessarily have adequate resistance to sulphide stress cracking when used in critical sour gas wells.

The following product analysis chemical composition requirements shall be specified for critical sour gas well casing and couplings (by grade, maximum or permitted range, in weight %):
The chemical composition specifications recommended in this IRP have been developed with consideration to both proprietary specifications and mill capabilities. In all cases, improvements to API 5CT as described above are within current mill capabilities, are within

<table>
<thead>
<tr>
<th>Element</th>
<th>J55 and K55</th>
<th>L80 Type 1</th>
<th>C90 Type 1</th>
<th>T95 Type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum OR Permitted Range, In Weight %</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Carbon</td>
<td>0.35</td>
<td>0.32</td>
<td>0.32</td>
<td>0.30(^1)</td>
</tr>
<tr>
<td>Manganese</td>
<td>1.40</td>
<td>1.20(^2)</td>
<td>1.00</td>
<td>0.75</td>
</tr>
<tr>
<td>Silicon</td>
<td>0.35</td>
<td>0.35</td>
<td>0.35</td>
<td>0.35</td>
</tr>
<tr>
<td>Phosphorus</td>
<td>0.020</td>
<td>0.020</td>
<td>0.015</td>
<td>0.010</td>
</tr>
<tr>
<td>Sulfur</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.005</td>
</tr>
<tr>
<td>Chromium</td>
<td>3(^3)</td>
<td>1.30</td>
<td>0.25 – 1.20</td>
<td>0.60 – 1.20</td>
</tr>
<tr>
<td>Molybdenum</td>
<td>4(^4)</td>
<td>0.65</td>
<td>0.15 – 0.75</td>
<td>0.30 – 1.00</td>
</tr>
<tr>
<td>Copper</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.15</td>
</tr>
<tr>
<td>Nickel</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.15</td>
</tr>
<tr>
<td>Aluminum</td>
<td>0.040</td>
<td>0.040</td>
<td>0.040</td>
<td>0.040</td>
</tr>
<tr>
<td>Niobium</td>
<td>0.0.35</td>
<td>0.040</td>
<td>0.040</td>
<td>0.010 – 0.040</td>
</tr>
<tr>
<td>Vanadium</td>
<td>5(^5)</td>
<td>0.050</td>
<td>0.050</td>
<td>0.050</td>
</tr>
<tr>
<td>Titanium</td>
<td>0.040</td>
<td>0.040</td>
<td>0.040</td>
<td>0.040</td>
</tr>
<tr>
<td>Boron</td>
<td>0.0025</td>
<td>0.0025</td>
<td>0.0025</td>
<td>0.0025</td>
</tr>
</tbody>
</table>

1 Carbon may be increased to 0.35% maximum and Phosphorus may be increased to 0.015% maximum if the molybdenum is 0.50% minimum.
2 Manganese may be increased to 1.40% maximum if the sulfur is 0.005% maximum.
3 Not normally added to this grade
4 Not normally added to this grade
5 Not normally added to this grade
economic limits and provide a significant increase in the performance of these tubulars in a critical sour gas well environment.

Elements not listed in the above table may not be added without the prior written consent of the qualified technical expert.

Manufacturers’ proprietary grades meeting the above chemical manufacturers’ propriety grades meeting the above chemical composition requirements must also meet all other API 5CT requirements for the equivalent grade. Casing joints shall be dual-marked with the API grade in addition to the manufacturer’s proprietary name.

The chemical composition requirements for electric resistance-welded ERW K55 may need to be more restrictive than specified above to ensure resistance to HIC and SOHIC.

- Typically, lower levels of C, Mn, P and S than the maxima specified in the table are required to impart resistance to HIC and to SOHIC.
- In addition, calcium treatment may be necessary to eliminate elongated Type II manganese sulphide inclusions. These inclusions have been associated with HIC development.
- ERW J55 and K55 requires HIC (IRP 1.4.15 J55 and K55 Casing: HIC Test Requirements) testing.

**Hardenability Requirements**

There are no hardenability requirements for Grade J55 and K55 casing and couplings.

Hardenability tests shall be conducted on Grade L80 Type 1 casing and couplings to meet the requirements of API 5CT for Grade C90 Type 1 and Grade T95 Type 1 casing and couplings.

The frequency of hardenability tests for Grade L80 Type 1 shall be per API 5CT for Grades C90 Type 1 and T95 Type 1.

There shall be a minimum of 90% as-quenched martensite in Grade L80 Type 1 per API 5CT for Grades C90 Type 1 and T95 Type 1.

**Mechanical Property Requirements**

Mechanical property requirements shall be per API 5CT.

**Hardness Requirements**

The following hardness restrictions are recommended for the sour service-rated grades identified in this IRP.

Casing and coupling manufacturing specifications should stipulate that testing be performed on the final product to confirm that these restrictions are met.

Testing shall be performed in accordance with API 5CT.

A hardness value is the average of three hardness readings or impressions per the API 5CT definition.
Table: 1.4.7.2 Hardness Requirements

<table>
<thead>
<tr>
<th></th>
<th>J55 and K55</th>
<th>L80 Type 1</th>
<th>C90 Type 1</th>
<th>T95 Type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hardness reading (max)</td>
<td>22.0 HRC</td>
<td>23.0 HRC</td>
<td>25.4 HRC</td>
<td>25.4 HRC</td>
</tr>
<tr>
<td>Hardness value (max)</td>
<td>22.0 HRC</td>
<td>22.0 HRC</td>
<td>25.0 HRC</td>
<td>25.0 HRC</td>
</tr>
<tr>
<td>Frequency – casing (one quadrant)</td>
<td>1/100 pipes or per heat&lt;sup&gt;6&lt;/sup&gt;</td>
<td>1/100 pipes or per heat&lt;sup&gt;7&lt;/sup&gt;</td>
<td>Alternate ends of every pipe</td>
<td>Alternate ends of every pipe</td>
</tr>
<tr>
<td>Frequency – couplings (four quadrants)</td>
<td>1/50 pipes or per heat&lt;sup&gt;6&lt;/sup&gt;</td>
<td>1/50 or per heat&lt;sup&gt;8&lt;/sup&gt;</td>
<td>Both ends of every pipe</td>
<td>Both ends of every pipe</td>
</tr>
</tbody>
</table>

Hardness variation for all the above grades shall be per API 5CT for grades C90 Type 1 and T95 Type 1.

**Grain Size Requirements**

There are no grain size requirements for Grade J55 and K55 casing and couplings.

Grain size determinations shall be conducted on Grade L80 Type 1 casing and couplings to meet the requirements of API 5CT for Grade C90 Type 1 and Grade T95 Type 1 casing and couplings.

The prior austenite grain size of Grades L80 Type 1, C90 Type 1 and T95 Type 1 casing and couplings shall be 7 or finer.

The frequency and method of grain size determinations shall be per API 5CT.

**Impact Toughness Testing Requirements**

Impact toughness testing shall be per API 5CT. The temperature for impact toughness testing shall be room temperature.

---

<sup>6</sup> Whichever is more frequent

<sup>7</sup> Whichever is more frequent

<sup>8</sup> Whichever is more frequent

<sup>9</sup> Whichever is more frequent
1.4.10. **SULPHIDE STRESS CRACKING SSC TEST REQUIREMENTS**

The following outlines the SSC testing requirements.

There are two protocols:

- Testing of all casing and couplings (IRP 1.4.11 NACE Testing Protocols).
- Pre-qualification of the manufacturer (IRP 1.4.13 Manufacturer Pre Qualification) and subsequent testing of selected casing and couplings.

1.4.11. **NACE TESTING PROTOCOLS**

1.4.11.1. **IRP NACE Testing Protocols**

Four static-loaded SSC test methods have been standardized by NACE International in Standard Test Method TM0177-96, “Laboratory Testing of Metals for Resistance to Specific Forms of Environmental Cracking in H₂S Environments”. The four test methods are:

- Method A – NACE Standard (Uniaxial) Tensile Test
- Method B – NACE Standard (Three-Point) Bent-Beam Test
- Method C – NACE Standard C-Ring Test, and
- Method D – NACE Standard Double-Cantilever-Beam (DCB) Test

Two test solutions (A and B) may be used with methods A, C and D:

- Test Method B has its own unique solution.
- Test Solution A is the original “NACE” environment.

Test Solution A is as aggressive as the most sour environment expected to be encountered in sour gas production, though may not be as aggressive as some acidizing environments if they have been contaminated with H₂S.

SSC testing of casing and couplings for critical sour gas service shall be performed in Solution A.

The principal stress on the casing is in the hoop (circumferential) direction, however the most commonly used SSC test Method (A) applies stress in the longitudinal direction.

The material properties in the longitudinal direction might not be representative of those in the hoop direction. Both Methods C and D more closely simulate the stress situation in casing.

Method C (C-Ring) specimens are typically not used to test casing because of the practical difficulties encountered when handling large specimens. However, the C-ring specimen is ideal for testing the weld areas of electric resistance-welded J55 and K55 and electric resistance-welded L80 Type 1 (if necessary) casing for resistance to SOHIC.

Method D (DCB) specimens do not have this size limitation, and are becoming more frequently used for the qualification of higher strength casing and couplings for critical sour service. The Method D test technique is not suitable for testing J55 and K55 casing because of the difficulty in initiating sulphide stress crack growth in this low strength material.
1.4.12. **Sulphide Stress Cracking SSC Test Procedures and Acceptance Requirements**

1.4.12.1. **IRP Test Procedures and Acceptance Criteria**

It is the responsibility of the purchaser / user to qualify the SSC test laboratory, (i.e., to confirm that they are capable of performing the SSC test method(s) correctly.)

Specimens shall be taken from material as close as possible to the internal surface of the casing or coupling.

The following procedures and acceptance criteria must be followed:

**Seamless J55 and K55 Casing and Couplings**

Testing shall be conducted in accordance with TM0177-96 Method A in the Solution A environment.

Standard size specimens shall be used. At least three specimens of each sample shall be tested to confirm the threshold stress.

Pass criteria are no failure and no visual observation of surface cracks per TM0177-96.

Metallography shall be conducted to determine whether cracks on the gauge length are environmentally induced.

The acceptance criteria shall be a threshold stress of 80 % SMYS minimum.

**Electric Resistance-Welded ERW K55 Casing**

The parent material shall be tested per the requirements and acceptance criteria for seamless K55 casing and couplings.

In addition, the weld area shall be tested in accordance with TM0177-96 Method C in the Solution A environment.

The weld shall be located at the apex of the Method C specimen. At least three specimens of each sample shall be tested to confirm the threshold stress.

Pass criteria are no failure and no visual observation of surface cracks per TM0177-96.

Metallography shall be conducted to determine whether cracks on the Method C specimen surface were environmentally induced.

The acceptance criteria shall be a threshold stress of 80 % SMYS minimum.

**L80 Type 1, C90 Type 1**

T95 Type 1 Casing and Couplings

Testing shall be conducted in accordance with TM0177-96 Method D in the Solution A environment.

Standard size specimens shall be used if wall thickness permits.

Sufficient specimens of each sample shall be tested to provide a minimum of three valid test results.
Specimens of L80 Type 1 and C90 Type 1 shall be fatigue-precracked. Specimens of T95 type 1 need not be fatigue-precracked.

After sufficient fatigue crack growth has occurred, the peak load shall be reduced by 35 %, and fatigue precracking shall continue for a further 20,000 cycles to sharpen the crack tip and avoid plastic deformation of material immediately ahead of the crack.

Specimen side arm displacements shall be in the middle of the ranges for each grade specified in TM0177-96.

Both parent material and weld area material of electric resistance-welded L80 Type 1 casing shall be tested. The DCB specimens of the weld area material shall be machined so that the weld is located at the bottom of the specimen side grooves.

Acceptance criteria shall be as follows for all grades and for both parent and weld area material:

- Standard size (B = 9.53 mm) specimens: An average $K_{1SSC}$ value of 33.0 MPa√m minimum, and a single specimen $K_{1SSC}$ value of 29.7 MPa√m minimum.

Subsize specimens: If casing or coupling size prevents the use of standard size specimens, subsize specimens shall be used. The manufacturer and the purchaser/user shall agree upon the acceptance criteria for subsize specimens. It is common practice to decrease the average and single specimen acceptance criteria for standard size specimens by 15 % for subsize (B = 6.35 mm) specimens, but the validity of doing this has not yet been substantiated through the application of fracture mechanics theory.

**Test Frequency**

Test frequency for all grades shall be one sample (i.e., one set of specimens) per heat per casing or coupling size per heat treat lot, unless the manufacturer is pre-qualified.

If the manufacturer is pre-qualified (see 1.4.13 Manufacturer Pre Qualification and 1.4.14 J55 And K55 & Electric Resistance – Welded ERW L80), subsequent testing of J55 and K55 or L80 Type 1 casing and couplings is optional.

**Sample Selection**

Test samples shall be obtained from material with the highest yield strength, as determined by the mandatory mechanical properties testing.

In the event that one or more samples have similar yield strength, the sample with the highest hardness values shall be selected for testing.

**Additional SSC Testing for Secondary Longitudinal Stress**

If the casing will be used in an application which results in an axial stress which is $\geq 50 \%$ SMYS (based on tube cross-sectional area), the purchaser/user shall require that quality assurance SSC testing be conducted in accordance with TM0177-96 Method A in the Solution A environment.

Test frequency for all grades shall be one sample (i.e., one set of specimens) per heat per casing or coupling size per heat treat lot, unless the manufacturer is pre-qualified.

Standard size specimens shall be used.
At least three specimens of each sample shall be tested to confirm the threshold stress. Pass criteria are no failure and no visual observation of surface cracks per TM0177-96. Metallography shall be conducted to determine whether cracks on the gauge length were environmentally induced.

The acceptance criterion for J55 and K55 casing and couplings shall be a threshold stress of 80 % SMYS minimum.

The acceptance criterion for L80 Type 1, C90 Type 1 and T95 Type 1 shall be a threshold stress of 90 % SMYS minimum.

1.4.13. MANUFACTURER PRE QUALIFICATION
1.4.13.1. IRP Manufacturer Pre – Qualification

The manufacturer shall be pre-qualified to supply casing and couplings by providing to the purchaser/user sufficient and persuasive SSC test data to satisfy the purchaser/user those materials with adequate resistance can be routinely and consistently provided.

Manufacturer pre-qualification may be accomplished through the provision to the purchaser/user of appropriate archival SSC test data, or by successfully completing an appropriate laboratory SSC test program.

The SSC test program outlined above (IRP 1.4.12 Sulfide Stress Cracking SSC Test Procedures and Acceptance Requirements) on selected samples is required for the pre-qualification of casing and couplings intended for use in critical sour gas wells:

Sample Requirements

At least three different heats of casing and three different heats of coupling stock (or individual couplings) shall be/shall have been tested as per IRP 1.4.12 Sulfide Stress Cracking SSC Test Procedures and Acceptance Requirements

The samples of casing and couplings tested shall have been produced in exactly the same manufacturing route as will be used for the materials for the critical sour gas well. In particular, the chemical compositions and heat treatment procedures shall be identical (within stated manufacturing tolerances).

The samples of casing and couplings tested shall have diameters and wall thicknesses comparable with those that will be used in the critical sour well. The wall thicknesses of at least two of the three samples shall not be less than that of the casing or couplings to be used in the critical sour well.


NACE International has not standardized a test method for SOHIC in tubular goods.

However, both NACE Methods A and C are capable of determining the susceptibility of tubular goods to SOHIC. The resistance to SOHIC of J55 and K55 casing and couplings will be determined when SSC tests are conducted in accordance with Clause 1.4.10 of this IRP. The SOHIC and SSC test acceptance criteria are identical.
SOHIC is of particular concern in normalized and normalized and tempered materials, (i.e., seamless and electric resistance-welded J55 and K55.)

SOHIC is less of a concern in materials given a quench and temper heat treatment.

If the use of electric resistance-welded L80 Type 1 casing is planned, a qualified technical expert shall determine whether testing for resistance to SOHIC is necessary.

1.4.15. J55 AND K55 CASING: HIC TEST REQUIREMENTS

1.4.15.1. IRP J55 and K55 Casing: HIC Testing Requirements

The following outlines the HIC testing requirements for J55 and K55 casing and couplings.

There are two protocols:

1. Testing of all casing and couplings as outlined below.

2. Pre-qualification of the manufacturer and subsequent testing of selected casing and couplings at the discretion of the purchaser/user. The protocol used for manufacturer pre-qualification (for acceptable SSC resistance) given in clause 1.4.11.1, and the same testing procedure and acceptance criteria as outlined below shall be followed.

- HIC testing is not required on a heat by heat (order) basis if the manufacturer has been pre-qualified.


Test frequency shall be one sample (i.e., one set of specimens) per heat, per casing size, per heat treat lot.

The samples of casing and coupling shall be tested in the same manner as required for seamless and electric resistance-welded linepipe.

Test environment shall be Solution A. It is mandatory to continuously bubble H₂S through the test solution for the duration of the test (after the initial saturation period) at the same rate as specified in TM0177-96 Method A.

It is mandatory to lightly etch the metallographic cross-sections of the tested specimens before examination for the presence of HIC damage.

Acceptance criteria shall be a sample average Crack Length Ratio (CLR) of 5.0 % maximum and a sample average Crack Thickness Ratio (CTR) of 1.5 % maximum. The sample average CLR and CTR are the average CLR and CTRs of all nine cross-sections (three cross-sections of each of three specimens). In addition, no single cross-section shall have a CLR which exceeds 25 % or a CTR which exceeds 10 %.
1.4.16. **Electric Resistance – Welded (ERW) Casing**

1.4.16.1. **IRP ERW Casing: Pressure Test Requirements**

All ERW casing must be hydro-tested to 100 % burst rating prior to manufacturer’s inspection.

1.4.17. **Casing Identification**

1.4.17.1. **IRP Casing Identification**

These materials shall be dual marked with the API monogram and the manufacturer’s proprietary grade identification/name.

1.4.18. **Inspection**

1.4.18.1. **IRP Inspection of New, Compliant Casing**

The following inspections are required for the detection of defects in casing and coupling stock (per API 5CT):

<table>
<thead>
<tr>
<th>Casing</th>
<th>J55 and K55</th>
<th>L80 Type 1</th>
<th>C90 Type 1</th>
<th>T95 Type 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Casings</td>
<td>SR1 is acceptable</td>
<td>SR2</td>
<td>SR2</td>
<td>SR2</td>
</tr>
<tr>
<td>Coupling stock</td>
<td>SR14</td>
<td>SR14</td>
<td>SR14</td>
<td>SR14</td>
</tr>
</tbody>
</table>

Special end area (SEA) inspection is required on every pipe length unless the manufacturer crops the pipe ends not covered by the automated pipe body inspection equipment.

Visual and magnetic particle inspection (MPI) of both the internal and external surfaces of the pipe ends for the presence of transverse and longitudinal defects shall be conducted.

The SEA inspection shall overlap the automated pipe body inspection by a minimum of 50 mm.

Exposed threads shall be visually inspected for damage. Consult API RP 5A5, “Field Inspection of New Casing, Tubing and Plain end Drill Pipe”, Section 4.4, for details of the required inspection.

1.4.18.2. **IRP Non – Compliant Casing: Testing and Inspection Requirements**

New casing and couplings not originally made in conformance with this specification are acceptable provided they pass the following inspection and testing requirements:

The casing and couplings shall be tested to confirm resistance to SSC, SOHIC and HIC per the requirements in this IRP. This requirement applies to J55 and K55 and L80 Type 1 as well as to C90 type 1 and T95 Type 1.

Special End Area inspection (SEA) shall be conducted on every joint of casing.
For grades J55 and K55 and L80 type 1, random surface hardness tests shall be conducted on one pipe in fifty and on all couplings (unless mill hardness testing records are available). Hardness tests shall be conducted on both pipe ends.

Hardness readings greater than 22.0 HRC shall be cause for rejection of the Grade J55 and K55 pipe or coupling, and for increased testing frequency of the remaining pipe.

Hardness readings greater than 23.0 HRC shall be cause for rejection or prove-up of the grade L80 type 1 pipe or coupling, and for an increased testing frequency of the remaining pipe. If any single hardness reading exceeds 23.0 HRC, two additional readings shall be taken in the same area to prove-up the pipe or coupling. The average of all the readings shall not exceed 22.0 HRC for the pipe or the coupling to be acceptable. The testing frequency shall be increased to every pipe.

Every joint must be traceable back to mill certificates documenting yield and tensile strength and chemistry at least.

Use of new, non-compliant grades C90 Type 1 and T95 Type 1 casing and couplings is not recommended.

**Note**  
Clause 1.4.19.2 is only intended to cover new pipe manufactured and purchased before the publishing date of this IRP (i.e., existing inventory).

### 1.4.19. Intermediate Casing

**IRP General**

Intermediate casing must meet the design specifications as outlined in this IRP.

### 1.4.20. Intermediate Casing Setting Depth

**1.4.20.1. IRP Intermediate Casing: Setting Depth**

Intermediate casing shall be set at a point before the cumulative release rate becomes critical.

**Note**  
ERCB regulations require intermediate casing be set at 3600m, or ERCB approval is required for a variance.

**1.4.20.2. IRP Intermediate Casing: Exemption**

Intermediate casing may not be required depending on the combination of the well type criteria described in 1.3.5 Well Types:

- Low Complexity well
- Low Impact well, and/or
- Simple ERP well.

This exemption must be approved by the appropriate regulatory agency and information outlined in 1.3.5 Well Types included in the project plan.

If the exemption from setting intermediate casing is approved, the wellbore integrity, including the casing and open hole sections, must be evaluated by an open-hole integrity...
test prior to penetrating the critical zone and must be found capable of holding anticipated formation pressures before continuing to drill without intermediate casing.

If the exemption from setting intermediate casing is approved, the surface casing grade must be suitable for sour service, (i.e., meet the specifications of this IRP).

If the exemption from setting intermediate casing is approved, kick tolerance calculations must demonstrate the ability of the surface casing and formation leak-off at the casing shoe, to handle a 3-cubic-metre gas kick.

1.4.21. **RE – ENTRY WELLS: GENERAL**

1.4.21.1. **IRP Re – Entry Wells: General**

Re-Entry well casing must meet the design specifications as outlined in this IRP.

A casing inspection log must be run and the casing design ratings must be calculated based on this data.

Specific documentation of suitable metallurgy or evidence of sulphide stress cracking resistance is required in order to qualify a casing which would not currently be considered sour service.

**Note** For a well to meet the specifications of this IRP, its age is likely to be less than 15 years old.

Metallurgy can be verified with mill certification or sample and testing of the top joint of a verified homogeneous string of casing.

The suitability of the existing casing’s metallurgy must be reviewed and approved by a qualified technical expert.

The casing must be pressure tested to 67 % of current formation pressure prior to drilling into the critical sour zone.
1.5. **BLOWOUT PREVENTER STACK**

1.5.1. **Scope**

The equipment considered includes all equipment which forms an integral part of the BOP stack, equipment directly attached to the stack (from below the rotary table to the casing bowl) and all BOP control systems.

**Design Considerations**

In selection of preferred BOP stack arrangements, it is necessary to accept the fact that equipment can fail, and to design a redundant system to reduce the effect of a failure. The design should take into account the probabilities of a given component failing and the probabilities of a given situation occurring.

The safety of the on site personnel is the most important factor in any design.

1.5.2. **BOP STACK CONFIGURATION**

1.5.2.1. **IRP Configuration**

Minimum stack components shall consist of an annular preventer, two spools and three rams.

An acceptable exception is that for maximum projected depths less than 1800 m, then flanged side outlets on the lower ram preventer may be substituted for the lower drilling spool.

The configuration of the BOP stack shall conform to Figures 1.5.1.1, 1.5.1.2, 1.5.1.3 and 1.5.1.4.

Configuration 3, Figure 1.5.1.3 should only be used where sufficient surface/intermediate casing is in place to contain maximum anticipated reservoir pressure because the closing of the lower pipe ram will result in the inability to bleed off pressure from the wellbore. Otherwise, the configurations 1 or 2 should be used.

1.5.2.2. **IRP Pipe Ram Sizes**

The pipe rams should be the correct size for the drill string used.

For drill strings with 2 pipe sizes, the top pipe ram should be sized for the larger pipe size. The lower pipe ram should be a variable bore ram sized for both pipe sizes. The top rams could also be variable bore.

If any rams are changed (e.g., casing rams) they must be pressure tested.
Figure: 1.5.1.1 BOP Stack Configuration 1

Symbols:

- Manually operated valve
- Check Valve
- HCR Valve (Either inside or outside of manual valve.)
Figure: 1.5.1.2 BOP Stack Configuration 2

To further improve the benefits of this configuration, a ram blanking tool (Figure 4) could be used when the drill string is out of the hole to allow the top ram to perform the function of a blind ram.

Symbols:

- Manually operated valve
- Check Valve
- HCR Valve (Either inside or outside of manual valve.)
To further improve the benefits of this configuration, a ram blanking tool (Figure 1.5.1.4) could be used when the drill string is out of the hole to allow the top ram to perform the function of a blind ram.
To further improve the benefits of this configuration, a ram blanking tool (Figure 4) could be used when the drill string is out of the hole to allow the top ram to perform the function of a blind ram.

1.5.3. **Shear Blind Rams**

Shear Blind Rams (SBR’s) would replace the blind rams in the BOP stack. They are designed to close and seal the open hole as normal blind rams. They are also designed to cut (shear) drillpipe, tools, wireline, etc., and allow the objects to drop out of the way of the rams, and then seal the open hole.
They would only be used if other well control equipment has failed, likely in the following circumstances:

- Inside blowout & leak in surface equipment
- Pipe rams & annular leak
- Out of hole (used as blind rams)

Shear blind rams provide a last chance opportunity to regain control of a well and therefore could prevent ignition (see 1.3.4 Emergency Response Plan).

However, if inadvertently or prematurely activated, that action could significantly hamper well control operations since once the drillpipe is sheared, the primary well control capability (i.e., circulation of weighted fluid) may not be immediately available.

### 1.5.3.1. IRP Shear Blind Ram Use Requirements

Shear blind rams must be used for any critical sour well where:

- the calculated emergency planning zone size intersects the boundaries of an urban centre, or
- the calculated emergency planning zone encompasses more than 100 occupied dwellings.

Shear Blind Rams should be used for most other critical sour wells unless the well is a low complexity, low impact and/or simple ERP well (see 1.3.5 Planning). The evaluation of the well should be based on the balance of these three components.

Whenever blind shear rams are not installed, the operator should evaluate running a drill string float / internal BOP (see 1.8.10 Downhole Floats).

### 1.5.3.2. IRP Shear Blind Ram Design Requirements

Sour Service: All SBR components including the shearing member(s) and internal bolting should meet the material standards as outlined in IRP 1.5.6 BOP Metallic Materials for Sour Service and 1.5.7 Non–Metallic Materials Requirements for Sour Service.

BOP Stack Configuration: SBR's replace the conventional blind ram in the preferred configurations (see 1.5.2 BOP Stack Configuration). There are no technical or operational advantages to having the SBR as an addition to the stack components illustrated. The SBR performs the same function as the blind ram when the drill string is out of the hole, and with similar reliability.

Casing design and setting depth should be reviewed to ensure the well can be effectively shut in (see 1.4.20 Intermediate Casing Setting Depth).

### 1.5.4. BOP Stack Auxiliary Equipment

**Choke Line Usage**

The choke line is the flow line off the BOP stack used to control the flow during the kill operation.
The top choke line should be used as the primary line and the bottom choke line should only be used as a back up system to control the flow in the well during a kill operation.

The bottom secondary spool should only be used as an emergency line to control the pressure during a component failure when the top primary spool is inoperative. Unless absolutely necessary, this bottom secondary spool is not to be used to kill the well. Instead, the failure should be repaired and kill procedure resumed.

**Wing Valves vs. Drilling Spool**

Wing valves on the casing bowl or on the intermediate spool should not be considered acceptable substitutes for a drilling spool.

**HCR Valve Position**

The position of the HCR valve should be at the contractor's and operator's discretion. The configurations outlined in 1.5.2 BOP Stack Configuration are recommended arrangements.

Special cases are always discussed when deciding whether the HCR valve should be located inside the manual valve. The inside location of the HCR offers advantages under special circumstances. Since the distance between the stack and HCR is shortened, the potential for plugging and freezing is reduced. This advantage becomes more important when high viscosity weighted drilling fluids are being used and in the case where mud rheological properties are affected by an H₂S influx. Alternatively, the outside position enables workers to isolate the well when servicing the HCR valve.

**Handwheels**

For manually locking rams, handwheels should be provided for each ram in a readily accessible location.

When using variable bore rams, check the manufacturer’s specifications closely. Some systems will not lock in two positions.

**Drilling Through Equipment**

Equipment items addressed include:

- Rotary tables
- Flow nipples
- Automatic pipe wiping devices
- Rotary drilling heads

The concern with auxiliary equipment installed above the annular preventer top and rig floor base is the potential interference with non routine well control situations (i.e., installation of snubbing units) where access to the topmost pressure rated flange on the annular through the rotary table is required.

All drilling through equipment above the top flange of the annular preventer should be designed and constructed to allow emergency access to that flange, i.e.:

- Be removed with the drill pipe still in place (split in two or stripped over the drill pipe)
• Open to a sufficient size to permit the installation of additional well control
equipment (i.e., an adapter / spacer spool of the same pressure rating as the BOP
stack) on top of the BOP stack.

Typical rotary table sizes may restrict the BOP stack which can be used, for example, if a
346 mm x 34,000 kPa BOP stack is used, a 699 mm rotary table would be required unless
the rotary can be split or stripped over drill pipe.

1.5.5. **BOP MECHANICAL SPECIFICATIONS: PRESSURE RATING AND CASING BOWLS**

1.5.5.1. **IRP Pressure Rating**

The pressure rating of a BOP stack is equal to the API pressure rating of the weakest stack
component. BOP stack components are casing bowls, valves, preventers, and flanges or any
other equipment directly attached to the stack / casing bowl that would experience stack
pressure (i.e., surface casing if intermediate casing is not required).

Required pressure ratings as per the appropriate regulations.

1.5.5.2. **IRP Casing Bowls**

Welded casing bowls shall be welded in accordance with an acceptable welding procedure
developed from API Spec 6A, “Specification for Wellhead and Christmas Tree Equipment”,
NACE MR-0175 and Section IX of ASME, Boiler and Pressure Vessel Code.

Threaded casing bowls shall be manufactured in accordance with API Spec 6A, the make-up
procedures and torque in accordance with API RP 5C1, “Care and Use of Casing and
Tubing”, and the thread compound used in accordance with 5A3 Thread Compounds for
Casing, Tubing, and Line Pipe.

Casing bowl outlets should be flanged for service on wells that have stack pressure ratings
of 21,000 kPa or greater as per API RP 53, Recommended Practice for Blowout Prevention
Equipment Systems for Drilling Wells.

1.5.6. **BOP METALLIC MATERIALS FOR SOUR SERVICE**

1.5.6.1. **IRP Metallic Material Requirements**

Applies to all pressure-containing components within the BOP stack, with the potential to be
exposed to H$_2$S gas, inclusive of:

• attached valves
• pressure gauges and sensors
• choke lines through to the outside valves of the choke manifold

All such components shall be constructed of materials that meet the standards of the

Sour Service Identification: Components should be marked in a manner that shows their
suitability, under NACE MR-0175, for sour service. Identification stamping procedures as
detailed in NACE MR 01 75 5.4 should be followed.
1.5.6.2. **IRP Bolting Requirements**

External bolt selection should be carefully considered relative to the potential for H₂S contact.

Subcomponents not normally exposed to hydrogen sulphide, such as external studs and nuts, are not required to meet NACE MR 0175 material standards (Note: API RP 53 does not permit this exception).

Specific rig configuration should be considered with respect to BOP ventilation, coverings, etc. to determine if, in fact, the studs and nuts could be exposed to H₂S.

With respect to external bolt selection, three options exist:

- Use of ASTM B7 & L7, which do not meet the sour service material requirements of NACE MR 01 756, but provides full API pressure rating, but results in SSCC susceptibility.
- Use of ASTM B7M & L7M, which meet the sour service material requirements of NACE MR 01 756 bolting provides SSCC resistance, but may require pressure derating of the BOP stack in some sizes (API 6). Identification and control of bolting during rig moves require special attention.
- Use of high strength, high alloy bolting, (such as ASTM 453 Grade 660), stamped A 2 or equivalent, is the third option. These bolting materials are SSCC resistant and of strength comparable to B7 bolting. Identification and control of bolting during rig moves require special attention.

1.5.7. **NON–METALLIC MATERIALS REQUIREMENTS FOR SOUR SERVICE**

1.5.7.1. **IRP Non-Metallic Material Requirements for Sour Wells**

Applies to the number of BOP Stack subcomponents which are constructed of non metallic components, including:

- annular preventer and ram rubbers
- bonnet or door seals
- packing for BOP secondary seals.

Non metallic materials for sour service should conform to API RP 53, 9.A.8.

As elastomer technology continues to evolve, consultation with the original equipment supplier as to the most suitable elastomers is recommended. Elastomers tend to be less tolerant than metallic materials due to the range of drilling environments encountered.

Detailed fluid properties and the range of operating conditions expected at the well should be addressed in the elastomer / drilling fluid selection process.
1.5.8. BOP TRANSPORTATION, RIGGING UP AND MAINTENANCE

Cold Work
During transportation, rigging up and maintenance of BOP stacks, operating practices should be used which avoid cold work, and hence hardening of equipment components. Any hammering action which could deform the stack component material should be avoided.

Replacement Parts
Material control for replacement parts for the BOP stack should have specifications and quality control equivalent to the original equipment.

Bolt Torque
Bolt up torque should be kept within the recommended range.

Component Marking
The marking of components with die stamps except where permitted by API 6A, Section VIII, should be avoided.

Welding
Welding of brace supports to BOP materials is not recommended. Where welding is required for component fabrication, the weldment and the heat affected zone of the welded components should possess essentially the same chemical and physical properties as the parent metals of the subcomponents. These include hardness properties and impact properties where appropriate. The weldment is also required to be free of linear defects, such as cracks, undercutting and lack of fusion.

Further details are contained in IRP 1.9 Welding.

1.5.9. 1.5.8 BOP CONTROL SYSTEMS

1.5.9.1. 1.5.8.1 IRP Hydraulic Pump Requirements
Two separate sources of hydraulic pressure should be provided to recharge the accumulators.

For low complexity, low impact, and simple ERP wells, one source can be considered. The nitrogen reserve system is not considered the second source of hydraulic pressure.

The pumps should have a working pressure equal to that of the accumulator system (API RP 53 5.A.11).

One of these units should start automatically when the accumulator pressure drops below 90% of its operating pressure (API RP 53 S.A.12).

The preferred combination of hydraulic power sources is one electric and one air powered. Alternative power sources as detailed in API RP 53 5.A.135 are acceptable.

One hydraulic power source should, without the accumulator, be capable of closing the annular preventer on drill pipe, opening the HCR valve and obtaining 1400 kPa above the accumulator precharge pressure within five minutes.
1.5.9.2. **IRP BOP Master Control Station Location**
The BOP master control shall be installed at a location remote from the rig floor.
The master control station should be located at ground level and remote from the rig floor, a minimum 15 m from well centre.
Locating the master BOP control station adjacent to the accumulators, or at an alternate ground level locations, desirable when drilling a critical sour well because this:
- Provides an opportunity to activate the BOPs in event of a fire on the rig floor or in the substructure.
- Provides an opportunity to activate the BOPs in event of a mechanical failure or interference with BOP control station on the rig floor.
- Provides greater potential for successfully rigging up an auxiliary BOP control system, specifically power and control lines, should the original systems be rendered inoperative.
- Provides individual control and return lines for each BOP element and HCR actuator.

1.5.9.3. **IRP Minimum Accumulator Sizing**
The accumulator system shall be sized such that when charged to its operating pressure and with the recharge pump off, there shall be sufficient volume to:
- open the HCR
- close the annular preventer on drill pipe
- and close, open, and close one ram preventer

The final accumulator pressure shall not be less than 8400 kPa. In addition, the accumulator must have sufficient volume to close the annular preventer on an open hole.

Where blind shear rams are run, the accumulator size must be increased, or a separate accumulator system installed, to provide sufficient volume and pressure to shear drill pipe.

**Accumulator System Recommendations**
The hydraulic manifold should be equipped with a full opening valve and provision for tie in of an auxiliary source of closing fluid (API RP 53 5.A.16a).

Provision should be made to isolate the accumulators and pumps from the BOP controls to facilitate the tie in of an auxiliary hydraulic power source (API RP 53 5.A.16b).

Provision should be made for isolation of accumulator banks into at least two sections.

If shear rams are included, the accumulator must be equipped with a hi-low pressure bypass valve to allow full accumulator pressure to the shear rams. This bypass valve must be identified and its proper use included in the Shearing Procedures (see 1.14 Practices)

**Hydraulic Fluid**
The fluid used in the hydraulic system should have a minimum pour point of $50^\circ$ C and should be of a type approved by the BOP manufacturer.
Nitrogen Reserve System
A nitrogen reserve system should be sized to:

- open the HCR valve
- and close both the annular preventer and one ram preventer
- and maintain at least 1400 kPa over the manifold pre charge pressure.

Provision should be included to isolate the nitrogen supply from the accumulator system.

If shear rams are included, a separate nitrogen booster system should be capable of meeting pressure and volume requirements to shear tubulars in use.

1.5.10. BOP INSPECTION AND SERVICING REQUIREMENTS

1.5.10.1. IRP Servicing Timing
All blowout preventer systems, including BOP valves and spools must be shop serviced and shop tested every three years.

As a minimum, any time a BOP stack is subjected to an uncontrolled flow of reservoir fluids, the stack should be shop serviced and tested prior to that stack going back into service. After a "serious" kick or a well control operation of extended duration, shop servicing should be carried out at the contractor's or operator's discretion.

Shop Servicing
A shop servicing of a BOP should include the minimum of:

- Complete disassembly of the preventer including all mechanical and hydraulic components.
- Visual inspection of all sealing surfaces and repairs where necessary.
- A record of all repairs done and parts repaired keeping in mind that the preventer is similar to a pressure vessel.
- All repairs and replacements shall meet the same requirement as the original preventer (NACE MR 01 75 and API RP 5.)

1.5.10.2. IRP Pressure Testing
A pressure test is to be done after reassembly.

Two pressure tests are required:

1. a low pressure (1400 kPa)
2. to the pressure rating of the BOP

The pressure test of all hydraulics is to be done in both the open and closed position, to a minimum pressure of 10,500 kPa or manufacturer's specification.

All pressure tests are to be conducted for a minimum of 15 minutes.

During drilling, the BOP pressure testing frequency is outlined in 1.14.3.1 IRP BOP Pressure Testing.
**Hardness Testing**

Hardness testing is to be conducted on any welding repairs, as per IRP 1.9 Welding.

**Documentation**

A common BOP shop testing and shop servicing form, similar to Test Report, Figure 1.5.9.1, should be completed by a qualified technical expert stating the date of the service test.

A certificate indicating the date at which it was last performed should be installed in a prominent position in the dog house.

A copy of the complete inspection report should be kept on file by the drilling contractor.
Figure: 1.5.9.1 Sample of Three Year Test Report

<table>
<thead>
<tr>
<th>BOP</th>
<th>Size</th>
<th>Working Pressure</th>
<th>Serial Number</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>mm</td>
<td>kPg</td>
<td></td>
</tr>
<tr>
<td>Single</td>
<td>Double</td>
<td>Triple</td>
<td>Rig</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Inspected By</th>
<th>Date</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Ram Location</th>
<th>Ram Description</th>
</tr>
</thead>
</table>

**INSPECTION**

<table>
<thead>
<tr>
<th>Door Screw Hole</th>
<th>Door Seal Area: Left</th>
<th>Right</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seat Condition</td>
<td>Ram Cavity</td>
<td></td>
</tr>
<tr>
<td>Skid Condition</td>
<td>Side Pad Condition</td>
<td></td>
</tr>
<tr>
<td>Seat-To-Skid Height mm</td>
<td>Wear mm</td>
<td>Side Pad Condition mm</td>
</tr>
<tr>
<td>Bore Condition</td>
<td>Bore Diameter</td>
<td></td>
</tr>
<tr>
<td>Ring Groove Condition</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Item | Stamp Code
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Left</td>
</tr>
<tr>
<td>Holder Condition</td>
<td></td>
</tr>
<tr>
<td>Mounting Slot Cond.</td>
<td></td>
</tr>
<tr>
<td>Holder Height mm</td>
<td>Wear mm</td>
</tr>
<tr>
<td>Holder Width mm</td>
<td>Wear mm</td>
</tr>
<tr>
<td>Block Height mm</td>
<td>Wear mm</td>
</tr>
<tr>
<td>Block Condition</td>
<td></td>
</tr>
<tr>
<td>Rubber</td>
<td></td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>Doors</th>
<th>Door Seal Groove</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Snap Ring Groove</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Ram Shaft Seal Cavity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Cylinder Stud Holes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Door Cap Screws</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hinges</td>
<td>Hinge Bore (I.D.)</td>
<td>mm</td>
<td>Wear mm</td>
<td>mm</td>
</tr>
<tr>
<td></td>
<td>Hinge Bore Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Hydraulic Ports</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Manifold Holes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Cap Screws</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Pin (I.D.)</td>
<td>mm</td>
<td>Wear mm</td>
<td>mm</td>
</tr>
<tr>
<td></td>
<td>Hinge Bore Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Pin Grooves</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Pin (O.D.)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hinge Pin Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Manifold Upper Pipe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Manifold Lower Pipe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>C</td>
<td>CYLINDER BORE</td>
<td>mm</td>
<td>Wear</td>
<td>mm</td>
</tr>
<tr>
<td>---</td>
<td>-------------</td>
<td>----</td>
<td>------</td>
<td>----</td>
</tr>
<tr>
<td></td>
<td>Cylinder Bore Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Head Hydraulic Port</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Head Cylinder Groove</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Head Seal Groove</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Studs and Nuts</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Locking Shaft Bore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P</td>
<td>PISTON O.D.</td>
<td>mm</td>
<td>Wear</td>
<td>mm</td>
</tr>
<tr>
<td></td>
<td>Piston O.D Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Wear Ring (O.D.) (1)</td>
<td>mm</td>
<td>Wear</td>
<td>mm</td>
</tr>
<tr>
<td></td>
<td>Wear Ring Condition (1)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Seal Groove (1)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R A M S H A F T</td>
<td>Threads</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R A M S H A F T</td>
<td>Threads Inside</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R A M S H A F T</td>
<td>Neck Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>R A M S H A F T</td>
<td>Foot End (O.D.)</td>
<td>mm</td>
<td>Wear</td>
<td>mm</td>
</tr>
<tr>
<td>R A M S H A F T</td>
<td>Foot End Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>L O C K I N G S H A F T</td>
<td>Threads</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>L O C K I N G S H A F T</td>
<td>Shaft (O.D.)</td>
<td>mm</td>
<td>Wear</td>
<td>mm</td>
</tr>
<tr>
<td>L O C K I N G S H A F T</td>
<td>Shaft Condition</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(1) Slim Line Only
1.5.10.3. Reference List

Alberta Government, ERCB, Oil and Gas Conservation Regulations 1986, ERCB, Calgary, Alberta.


API, Care and Use of Casing and Tubing, Eighteenth Edition, May 1999 RP 5C1, Dallas, Texas.


NACE, Petroleum and Natural Gas Industries - Materials for Use in H₂S-containing Environments in Oil and Gas Production - Parts 1, 2 and 3, 2003 NACE MR0175/ISO 15156, Houston, Texas
1.6. **CHOKE MANIFOLD**

1.6.1. **SCOPE**

The equipment considered includes the choke manifold and choke / kill lines, including metallurgy requirements.

Choke lines discussed in this document refer to the line between all BOP stack valves and the choke manifold.

The kill line refers to the section between the mud pump manifold and the BOP stack valves.

Manifold location, housing, configuration, and auxiliary equipment are included with respect to manifold requirements.

Choke / kill line and manifold metallurgy covers qualification of existing equipment, use of flexible hose, fabrication and certification of new installations and documentation of qualified manifolds.

1.6.2. **CHOKE MANIFOLD GENERAL**

1.6.2.1. **IRP Choke Manifold Design Specifications**

The manifold and piping shall provide complete redundancy from the BOP stack, through the manifold, to the mud-gas separators, and finally to the flare pit.

Figure 1.6.1.1 outlines the recommended manifold layout.

Where only one mud-gas separator is being used, redundancy from the manifold to the single mud-gas separator and from the mud-gas separator to the flare pit is not required.

**Bleed Off Lines**

A separate bleed-off line from each spool to a separate manifold wing (side) is required and must be equipped with a separate casing pressure gauge.

**Chokes**

A remote, hydraulic operated, non-rubber sleeve choke is required on the primary manifold wing (upper BOP spool) and a manual operated choke is required on the secondary manifold wing (lower BOP spool).

Each choke should be capable of being routed through either wing of the control manifold.

**Material Specifications**

Equipment for manifold systems should conform to API Spec 6A.

All components and materials including valves, chokes, lines, and fittings should comply with NACE MR 0175.

**Lines and Fittings**

Lines should be kept as straight as possible leading up to the preferred horizontal manifold configuration.
Fitting (tee and cross) and pipe materials should be consistent. Internal diameters of fittings should be matched to pipe ID.

**Welding**

All welds should be 100% radiographed after being stress relieved, and documented as described in IRP 1.9 Welding.

**Winter Operations**

For winter operations, the manifold and related piping should be filled with water-soluble antifreeze which is compatible with the manifold components. Diesel is not recommended for use as antifreeze since diesel / mud segregation may allow an accumulation of water based fluids and line blockage.

**Figure 1.6.1.1 Choke Manifold Layout**

![Choke Manifold Layout Diagram]
1.6.3. 1.6.2 VALVES & CHOKES

1.6.3.1. 1.6.2.1 IRP Valve and Choke Specifications

Valve specifications should require full bore gate valves with an opening equal to or greater than manifold piping ID.

Valve bodies and bonnets should be constructed of forged or cast API Type 2 material.

Valves with integral flanges are preferred and are to be compatible with piping flanges.

Valves should be furnished with secured hand wheels indicating the direction of valve opening.

If appropriate, the preferred pressure side of valves which are designed for working pressure should be clearly marked.

Adjustable choke specifications should identify the fully open and the fully closed position on the choke body and on the actuator, if so equipped. Recommended choke body materials include API Type 2 AISI 8720 or equivalent. Inlet and outlet flanges should meet or exceed manifold pressure rating.

1.6.4. FLANGES, RING GASKET AND BOLTING

1.6.4.1. IRP Flanges, Ring Gaskets and Bolting Specifications

Flanges should be utilized throughout without interconnection of API and ANSI types.

Table 1.6.3.1 Recommended API Flange – Choke/Kill LineCombinations should be utilized for specifying API Pipe / Flange combinations.

R or RX rings should be used on API 6B flanges while BX rings should be used on API 6BX flanges. Ring types BX 150 through BX 160 should not be reused. Suitable gasket materials should be determined from API Spec 6A.

ASTM A193 Grade B7M or ASTM A32 Grade L7M studs are recommended on jacketed flanges. Hardness should be limited to HRc 22 when utilizing Proprietary Grade B7X.

ASTM A194 Grade 2HM or 7M nuts are recommended on jacketed flanges. Hardness should be limited to HRc 22 when utilizing proprietary Grade 2HX nuts.
Table 1.6.3.1 Recommended API Flange Choke/Kill Line Combination

<table>
<thead>
<tr>
<th>FLANGE</th>
<th>ERCB Class</th>
<th>Type</th>
<th>Material</th>
<th>Normal Size (Include)</th>
<th>Actual ID (mm)</th>
<th>Actual OD (mm)</th>
<th>Press Rating (mPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class II</td>
<td>API 68</td>
<td>API Type 4</td>
<td>2 1/16</td>
<td>52.50</td>
<td>60.5</td>
<td>13.8</td>
<td></td>
</tr>
<tr>
<td></td>
<td>API 68</td>
<td>API Type 4</td>
<td>3 ⅛</td>
<td>77.93</td>
<td>88.9</td>
<td>13.8</td>
<td></td>
</tr>
<tr>
<td>Class III</td>
<td>API 68</td>
<td>API Type 4</td>
<td>2/16</td>
<td>52.50</td>
<td>60.5</td>
<td>13.8</td>
<td></td>
</tr>
<tr>
<td></td>
<td>API 68</td>
<td>API Type 4</td>
<td>3 ⅛</td>
<td>77.93</td>
<td>88.9</td>
<td>13.8</td>
<td></td>
</tr>
<tr>
<td>Class IV</td>
<td>API 68</td>
<td>API Type 4</td>
<td>2/16</td>
<td>49.25</td>
<td>60.5</td>
<td>20.7</td>
<td></td>
</tr>
<tr>
<td></td>
<td>API 68</td>
<td>API Type 4</td>
<td>3 ⅛</td>
<td>73.66</td>
<td>88.9</td>
<td>20.7</td>
<td></td>
</tr>
<tr>
<td>Class V</td>
<td>API 68</td>
<td>API Type 4</td>
<td>3 ⅛</td>
<td>66.65</td>
<td>88.9</td>
<td>34.5</td>
<td></td>
</tr>
<tr>
<td>Class VI</td>
<td>API 68x</td>
<td>API Type 2</td>
<td>3 1/16</td>
<td>777.8</td>
<td>110.3</td>
<td>69.0</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>PIPE</th>
<th>Type &amp; Grade</th>
<th>Nominal Pipe Size (Inches)</th>
<th>Linear Density (KG/M)</th>
<th>Actual ID (mm)</th>
<th>Actual OD (mm)</th>
<th>Wall Thk. (mm)</th>
<th>(1) Min. Wall (mm)</th>
<th>(2) Calc. Press Rating (mPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AP1 X46</td>
<td>2</td>
<td>5.43</td>
<td>52.50</td>
<td>60.3</td>
<td>3.91</td>
<td>1.5</td>
<td>35.98</td>
<td></td>
</tr>
<tr>
<td>AP1 X46</td>
<td>3</td>
<td>11.28</td>
<td>77.93</td>
<td>88.9</td>
<td>5.48</td>
<td>2.2</td>
<td>34.25</td>
<td></td>
</tr>
<tr>
<td>AP1 X46</td>
<td>2</td>
<td>5.43</td>
<td>52.50</td>
<td>60.3</td>
<td>3.91</td>
<td>1.5</td>
<td>35.98</td>
<td></td>
</tr>
<tr>
<td>AP1 X46</td>
<td>3</td>
<td>11.28</td>
<td>77.93</td>
<td>88.9</td>
<td>5.48</td>
<td>2.2</td>
<td>34.98</td>
<td></td>
</tr>
<tr>
<td>AP1 X46</td>
<td>2</td>
<td>7.47</td>
<td>49.25</td>
<td>60.3</td>
<td>5.53</td>
<td>2.25</td>
<td>50.94</td>
<td></td>
</tr>
<tr>
<td>AP1 X46</td>
<td>3</td>
<td>15.25</td>
<td>73.66</td>
<td>88.9</td>
<td>7.62</td>
<td>3.31</td>
<td>47.57</td>
<td></td>
</tr>
<tr>
<td>ASTM A106 Schedule 160 Grade B G</td>
<td>3</td>
<td>21.32</td>
<td>66.7</td>
<td>88.9</td>
<td>11.12</td>
<td>7.25</td>
<td>60.39</td>
<td></td>
</tr>
<tr>
<td>API</td>
<td>3(3)</td>
<td>27.65</td>
<td>58.42</td>
<td>88.9</td>
<td>15.24</td>
<td>9.07</td>
<td>115.82</td>
<td></td>
</tr>
</tbody>
</table>

Note

(1) Based on API burst formula and required pressure integrity, assuming uniform wear.

(2) Based on API burst formula P=0.875 (2 Ys t)
where $Y_s = \text{Min. Material Yield}$

$t = \text{wall thk.}$

$D = \text{Nominal OD}$

(3) Requires weldneck flange transition piece to match flange and pipe boxes

1.6.5. **FLEXIBLE STEEL HOSES**

1.6.5.1. **IRP Flexible Steel Hose Specifications**

Flexible steel hoses are an acceptable alternative to interconnect rigid steel lines to BOP spool outlets or other rigid steel lines.

Full length flexible steel hoses or kill lines will be permitted, but are not universally recommended because they may be subject to external damage and therefore, may not provide the most desirable type of installation.

**Pressure Integrity**

Flexible hose assemblies should possess pressure integrity rating to working pressure for any temperature from $90^\circ\text{C}$ down to $-40^\circ\text{C}$. This rating should always equal or exceed rating of BOP stack.

**Internal Diameter**

Internal diameters of flexible hoses should be consistent throughout.

**Flanges**

Flanges compatible with BOP and choke manifold connections should be used for end connectors.
Material Specifications

Specifications should include demonstration of capability of a representative assembly to withstand 25% H₂S in water saturated methane at 90% for a minimum of 24 hours at rated working pressure without leaking.

All metal components which may be exposed to sour fluid (including connectors) should meet NACE MR 01 75.

The material used in the internal bore should exhibit a high degree of abrasion resistance. In addition, the material should not be susceptible to degradation by exposure to any of the following fluids:

- fresh or salt water
- #1 or #2 diesel fuel with aniline points over 60 °C
- water based, oil based, or mineral oil based drilling fluids
- sweet or sour gas or condensate
- CO₂ or water glycol solutions

Anchoring & Bends

All flexible hoses should be supported and anchored in accordance with manufacturer's recommendations.

Support and anchoring devices should not be allowed to produce localized bends.

Any bends should occur at a point remote from end fittings and should contain a bend radius safely in excess of manufacturer's specified minimum.

Bends with radius 1.5 times greater than specified minimums are preferred.

Heat Tracing

Heat trace temperatures should be controlled when winterizing hoses to avoid thermal degradation of non metallic flex hose components

IRP Flexible Steel Hose: Testing & Documentation

New hose assemblies should pass a hydrostatic test at 1.5 times the working pressure rating for a minimum of five minutes. Manufacturer should be requested to verify successful compliance with this test.

Used hose assemblies should be pressure tested at least every three years to 70% of new hose test pressure for ten minutes using a low viscosity solids free fluid. For standard stack and manifold pressure tests, the flexible hose should be pressure tested to the BOP stack rating.

Suitable types of flexible hose should be demonstrated to be capable of withstanding 450 °C of direct flame exposure for a minimum of 15 minutes at 10.4 MPa applied pressure.

Pressure testing should coincide with frequency for shop servicing of BOPs (1.5.9). Special attention should be paid to pressure testing when using flexible hose, due to the difficulty in assessing the condition of the pipe wall through conventional inspection means.
Note

Inspection of flexible hoses may not be straightforward since areas subject to erosion are difficult to locate due to a variable bend location from well to well. In addition, ultrasonic thickness testing is somewhat meaningless for flexible hose. Consequently, special attention should be paid to pressure testing of flexible hose to determine integrity for continued service. Since field inspections are difficult, the periodic shop inspections are considered quite important to evaluate the detailed condition of flexible hose.

Permanent markings on the flexible hose assembly should be visible and include the working, test and burst pressure ratings, manufacturer and date of manufacture, and minimum bend radius.

1.6.6. Pressure Gauges

The manufacturer, style, and physical size of pressure gauges and sensors should be left to the contractor’s / operator’s discretion.

1.6.6.1. IRP Standpipe and Casing Pressure Gauges

Existing standpipe gauges can be utilized on critical wells providing they do not significantly exceed the BOP or manifold rating.

Except in the cases of Classes I and II rigs, the capability to install a low pressure gauge (7000 kPa) to supplement the standpipe gauge is recommended. This gauge should be installed in parallel with the existing standpipe gauge and must be protected by a pressure limiting device or a needle valve rated at least as high as the BOPs and manifold. Where sensors are used to supply signals to the low pressure gauge, a diaphragm type is preferred.

The capability to install a low pressure (7000 kPa) casing gauge to supplement the regular casing pressure gauge is recommended.

This low pressure gauge when utilized should be installed in parallel and must be protected by a pressure limiting device or a needle valve rated at least as high as the BOPs and manifold. For greatest accuracy at low pressures, diaphragm sensors are preferred to supply signal to the low pressure casing gauge.

The use of excessively higher casing pressure range gauges than required for the BOP pressure rating is to be avoided. Examples of such ranges would be 70,000 or 105,000 kPa gauges on 21,000 or 35,000 kPa manifolds.

Recommended casing pressure gauge range is approximately 125 % to 167 % of the maximum pressure that may be encountered and at least 110 % of the BOP manifold working pressure rating.

Compound mud gauges employing dual bourdon tubes are an acceptable alternative to dual gauge installations.

These gauges present both low and high pressure ranges using independent indicators on a single gauge face.

The low pressure gauge is protected by a built in pressure limiting device.
Diaphragm sensors are preferred to supply signals to these gauges for increased accuracy on the low pressure scale.

Compound gauges may be used either on the drill pipe or casing pressure side.

**1.6.6.2. 1.6.5.2 IRP Choke Panel Pressure Gauges**

Choke panel gauges with ranges excessively higher than the choke manifold rating are not recommended.

Remote drill pipe pressure gauges should be readable from the choke location.

A remote operated choke is required on all critical sour wells. A remote casing pressure gauge would then be available at or near the driller's console to maximize the information while circulating out a kick.

A remote drill pipe pressure gauge should be installed or readily accessible at the choke manifold for all BOP classes. As a minimum the line must be laid to the manifold. These provisions are considered adequate for most applications.

Assuming there is a tie in for a low-pressure gauge, the need for a second high pressure gauge should be left to the operator’s / contractor’s discretion on all wells.

Installation of gauges and sensors should be in a vertical or near vertical position to reduce the chance of solids build up. Isolation valves should be utilized so that operations need not be shut down in the event of a failure.

Casing pressure gauges should be checked monthly for proper operation by pressurizing the choke line side of the sensor, when conducting a pressure integrity test through the choke manifold or pressure testing a new casing string.

A function test of the casing gauge should be conducted prior to penetration of the critical zone.

**1.6.6.3. IRP Pressure Sensor Maintenance and Testing**

Maintenance of sensors should be conducted at least monthly and prior to penetration of the critical zone.

In general, diaphragm sensors are favoured for lower pressure applications such as those found on Class I to Class IV rigs. Similarly, piston sensors are generally favoured for higher pressure applications such as Class IV to Class VI rigs.

Gauge calibration and testing should be conducted by means of cross checking during BOP pressure tests. This can be done by comparison with reference gauges kept by the rig supervisor or operator’s representative, or by comparison with pressure test truck readings.

Errors exceeding +5% of actual test pressure on the high-pressure gauge will require gauge replacement, unless the gauge is equipped with a manual adjustment feature and is still operating within its acceptable adjustment range.

Diaphragm sensors exhibit excellent sensitivity and consistent performance although they are relatively easy to damage. They must be inspected or replaced periodically to ensure segregation of the drilling mud and gauge liquid, such as glycol, low temperature hydraulic fluid, or instrumentation fluid. The diaphragm type sensors are not designed to withstand
differential pressure and therefore may be subject to rupture if the gauge liquid chamber is not completely filled.

Piston style sensors are considerably more rugged and less prone to catastrophic failure. They do, however, exhibit somewhat jerky or stair step pressure build up especially after piston or sleeve wear is significant. This irregular pressure build up is caused by a threshold differential pressure required to overcome friction and may be only a few kPa to perhaps a few hundred kPa.

The pressure on the gauge side of the sensor may be less than the true pressure by a value approximated by the threshold friction pressure of the sensor. Piston friction may be particularly evident when the drilling fluid is heavily solids laden.

Studies have also shown that piston sensors may yield higher than actual gauge readings when the casing or drill pipe pressure is declining.

This hysteresis error as well as lower sensitivity is significant at the lower end of the pressure range but is acceptable at higher pressures. Piston sensors are particularly suitable for long hose runs (exceeding 15 m) or for applications where multiple gauges are driven by one sensor.

Routine maintenance of sensors would be conducted approximately as follows:

- Knock off the union from the mud side of the sensor,
- inspect bladder or piston O rings and sleeve,
- remove any solids accumulation,
- replace the union, and
- check for leaks.

1.6.7. **Initial Choke Manifold Certification and Documentation**

1.6.7.1. **IRP Choke Manifold Certification and Documentation**

Manifold documentation should be retained by the equipment owner and updated following any changes or replacements.

Documentation should include component mill certificates with written confirmation indicating compliance with NACE criteria. All welds should be 100% radiographed for initial certification and documented.

Component mill certificates should be obtained for all new equipment for purposes of initial certification. The following information should be supplied for each component:

- name of manufacturer
- date of manufacture
- serial number
- part numbers and lot numbers (to allow tracking to mill certification)
- material grade
• chemistry
• physical properties
• actual hardness
• heat treatment used
• confirmation of compliance with NACE criteria

One flange of each component should be die stamped with a unique identifier. It is recommended that the unique identifier be cross referenced via documentation to the inspection company, year and month of inspection and component number.

All valves passing inspection should be tagged to indicate subsequent disassembly.

The assembled system should be pressure tested to rating using a low viscosity, solids free liquid.

Component suitability, manifold assembly, pressure testing and identification should be witnessed and approved by a certified inspection company.

A detailed manifold and piping schematic illustrating individual component parts and unique identifier should be prepared.

Maintenance and repair of equipment should be conducted in accordance with manufacturer's recommendations. All repairs, including weldments, should be certified by a qualified inspection company and fully documented.

1.6.8. **CHOKE MANIFOLD SHOP SERVICING AND PRESSURE TESTING**

1.6.8.1. **IRP Choke Manifold Shop Servicing**

Regular shop servicing of BOP choke manifolds is not required if the manifold has been properly maintained and regularly pressure tested.

However, after a serious kick or a well control operation of extended duration, the manifold and related piping should be inspected and tested as follows:

• The choke(s) and valves used in the well control operation should be disassembled and the internals visually inspected. Any components, which show signs of damage or serious wear, should be replaced. The reassembled choke and valves should be pressure tested to meet or exceed original manufacturer's specifications.

• Ultrasonic thickness testing of piping and related fittings should be considered with special attention given to areas of change in piping direction. Any remaining wall which will not meet the working pressure at the minimum yield strength should be replaced.

If a manifold has not been in recent service, or the operational history of the manifold is unknown, the a shop service and test should be done.
1.6.8.2. **IRP Choke Manifold Pressure Testing Procedures**

The integrity of the BOP choke manifold and its related piping should be established by hydrostatically pressure testing to full work rating.

A solids free, environmentally acceptable fluid should be used for pressure testing.

The manifold and all piping upstream of the choke should be pressure tested to manifold working pressure rating. Each valve should be individually tested in both the open and closed position, with the exception of the last valve in a series, which is only tested closed.

During drilling, the choke manifold pressure testing frequency is outlined in [1.14.3.3 IRP Choke Manifold Pressure Testing](#).
1.7. **MUD GAS SEPARATORS**

1.7.1. **Scope**

This IRP addresses the minimum mud-gas separator requirements for critical sour wells.

The technical specifications contained in this IRP are directed at providing adequate capacity to handle kicks of considerable volume without exceeding the acceptable back pressure in the vessel and while maintaining good mud gas separation efficiency.

Two types of mud-gas separators are addressed:

1. Open bottom, atmospheric pressure mud gas separators
2. Closed, pressurized mud gas separators

Inlet line and vent lines are also addressed.

Recommended materials, fabrication, installation, and maintenance guidelines are outlined.

Certification and documentation are also addressed.

The designs presented are best practices at time of writing, however, alternate designs are acceptable provided they are thoroughly engineered and have been reviewed through some type of hazard and operability review.

1.7.2. **General Requirements**

1.7.2.1. **IRP Mud – Gas Separator General Requirements**

Two mud-gas separation devices are required for the drilling of critical sour wells. However, one mud-gas separator is acceptable upon approval from the appropriate regulatory agency provided that the well is a low complexity, low impact and/or simple ERP well (see 1.3.5 Well Types). The evaluation of the well should be based on the balance of these three components.

One device must be an atmospheric, open bottom, mud-gas separator and must conform to the specifications detailed in Table 1.7.2.1. Open bottom mud gas separators are recommended for critical sour drilling for their simplicity, lack of moving parts, and high reliability.

Production interval history should be accessed to provide gas rates and liquid production potential to determine mud system contamination possibilities. If the zone of interest is known to produce hydrocarbon liquids or water, consideration should be given to using a pressurized separator.

Each separator is to be fed independently with separate inlet lines from each wing of the choke manifold. Choke and piping arrangement from the manifold shall allow independent control of flow to each mud gas separator.

Each separator requires its own vent line run independently to the flare facility. (i.e., flare stack, flare pit, incinerator).
All materials used in vessels, inlet lines, and vent lines for mud-gas separators must be suitable for sour service and have a maximum yield strength not exceeding 550 megapascals. Suitable materials are detailed in Table 1.7.2.2.

Mud-gas separator vent lines shall slope down towards the flare pit.

1.7.3. **Open Bottom Mud – Gas Separators**

1.7.3.1. **IRP Open Bottom Mud – Gas Separator Specifications**

The recommended configuration for atmospheric pressure Open Bottom Mud-Gas Separators are given in Figure 1.7.2.1.

The vessel should be positioned in the first mud tank compartment downstream of the sand trap or shale shaker. It should be installed away from tank corners and 0.5 m or more away from tank walls. Such horizontal positioning is more important when using shallower submersion depths such as 1 m. In all cases the vertical position should be such that the base is 0.3 m or more above the mud tank floor. The vessel should be removable and the compartment housing the vessel shall be equipped with a dump gate.

An alternate configuration would be to place the Open Bottom Mud-Gas Separator(s) in a remote tank as described in IRP 1.7.6 Remote Open Bottom Mud-Gas Separators.

Dimensional specifications for atmospheric pressure Open Bottom Mud-Gas Separators are given in Table 1.7.2.1.

Materials used for vessel body and head should have a maximum yield strength of no greater than 550 MPa. Recommended materials and fittings are outlined in Table 1.7.2.2.

Spiral welded pipe should not be used for mud gas separator bodies.

Weldments on external fittings such as vessel inlet and outlet flanges should be reinforced and stress relieved.

Wall thickness for open bottom mud gas separator vessels should be no less than 6 mm, with considerably thicker walls preferred. Allowances for additional wall thickness for erosion and corrosion should be considered.

Flat topped vessels are not recommended.

Increased wall thickness in the inlet area should be considered when tangential inlet nozzles are utilized. The internal profile of the vessel head should smoothly direct separated gas into the vent line.

Internal components should be properly designed and positioned to augment separation efficiency. To facilitate removal and repairs, internal components subject to wear should not be welded in place. If internal components are welded in place, the wall behind such locations may be difficult to inspect for signs of corrosion.

The inspection opening (access hatch) should be sized and positioned to facilitate inspection and refurbish of internal components. Vessel plate materials are suitable for fabrication of inspection hatch. The inlet line flange doubling as an inspection opening is an acceptable alternative. Figure 1.7.2.1 illustrates a suggested configuration for atmospheric open bottom mud gas separators.
Tank fluid level (head) is to be maintained equal to or greater than fluid height requirements as indicated in Table 1.7.2.1. The compartment housing the separator should be checked frequently to avoid solids build up around the bottom of the vessel.

**Figure 1.7.2.1 Open Bottom Mud – Gas Separator; Suggested Configuration**

![Diagram of Open Bottom Mud - Gas Separator]

(See Table 1.7.2.1 Open Bottom Mud – Gas Separator; Dimensions)
### Table 1.7.2.1 Open Bottom Mud – Gas Separator; Dimensions

(See Figure 1.7.2.1 Open Bottom Mud – Gas Separator; Suggested Configuration)

<table>
<thead>
<tr>
<th>Separator Configuration</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>“letters” refer to Figure 1.7.2.1</strong></td>
<td></td>
</tr>
<tr>
<td>D</td>
<td>Separator Inside Diameter</td>
</tr>
<tr>
<td>d</td>
<td>Vent Line Inside Diameter</td>
</tr>
<tr>
<td>L</td>
<td>Liquid Level</td>
</tr>
<tr>
<td>V</td>
<td>Vapour Space</td>
</tr>
<tr>
<td>LG</td>
<td>Liquid-Gas Disengagement Space</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Separator Placement in Mud Tank</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td>Open Bottom Underflow</td>
</tr>
<tr>
<td>S</td>
<td>Distance to Tank Wall</td>
</tr>
</tbody>
</table>

### Separator Internals

Impingement Plate: if used, it should be removable and made from an abrasion resistant material. Do not weld the plate directly to the separator body.

Baffles: should be installed to augment separator efficiency.

### Inside Diameter (D) & Vent Line (d) Specifications

<table>
<thead>
<tr>
<th>Drilling Depth Less Than m</th>
<th>Minimum Vessel Inside Diameter (D) mm</th>
<th>Minimum Vent Line Inside Diameter (d) mm With 1 m of Liquid Level (L)</th>
<th>Minimum Vent Line Inside Diameter (d) mm With 2 m of Liquid Level (L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>750</td>
<td>355.6</td>
<td>101.7</td>
<td>101.7</td>
</tr>
<tr>
<td>1800</td>
<td>609.6</td>
<td>152.4</td>
<td>127.0</td>
</tr>
<tr>
<td>2700</td>
<td>660.4</td>
<td>172.9</td>
<td>152.4</td>
</tr>
<tr>
<td>3600</td>
<td>762.4</td>
<td>203.2</td>
<td>152.4</td>
</tr>
<tr>
<td>5000+</td>
<td>914.4</td>
<td>254.0</td>
<td>203.3</td>
</tr>
</tbody>
</table>

Vessel diameter was determined using a vapor load constant \( k \) of 0.11 /s
Table 1.7.2.2 Open Bottom Mud – Gas Separator Vessel and Vent Line Materials

<table>
<thead>
<tr>
<th>Regular Materials</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Plate:</td>
<td>ASTM A516</td>
</tr>
<tr>
<td></td>
<td>Grade 65</td>
</tr>
<tr>
<td></td>
<td>ASTM A516</td>
</tr>
<tr>
<td></td>
<td>Grade 70</td>
</tr>
<tr>
<td>Body and Piping</td>
<td>ASTM A106</td>
</tr>
<tr>
<td></td>
<td>Grade 8</td>
</tr>
<tr>
<td></td>
<td>ASTM A53</td>
</tr>
<tr>
<td></td>
<td>Grade 8</td>
</tr>
<tr>
<td></td>
<td>API 5L</td>
</tr>
<tr>
<td></td>
<td>Grade 8</td>
</tr>
<tr>
<td></td>
<td>API 5L</td>
</tr>
<tr>
<td></td>
<td>Grade X42</td>
</tr>
<tr>
<td></td>
<td>CSA Z245.1</td>
</tr>
<tr>
<td></td>
<td>Grade 241 Category I</td>
</tr>
<tr>
<td></td>
<td>API H41, J55&lt; K55</td>
</tr>
<tr>
<td></td>
<td>seamless casing</td>
</tr>
<tr>
<td></td>
<td>(if hardness tested)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Low – Temperature Materials</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plate:</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Inlet Piping</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

1.7.4. **Inlet Lines for Mud – Gas Separators**

1.7.4.1. **IRP Inlet Lines for Mud – Gas Separators (Both Atmospheric and Pressure)**

Since these lines may be exposed to physical and thermal shock, low temperature tough rated materials are recommended. Table 1.7.2.2 outlines recommended materials and fittings and illustrates grades rated low temperature tough.

Only seamless pipe is recommended for use as inlet lines.

Line diameter should be 25.4 mm (1") larger O.D. than the BOP choke line outside diameter to limit maximum flow velocity to the mud-gas separator.

Inlet lines to the mud-gas separators should be accessible full length and it is recommended no portion of the line be submerged in drilling mud or positioned between bulkheads. If the line is submerged, it must be inspected for wall thickness (UT) and integrity prior to spud of the critical sour well.

The line should also be kept as straight as possible with internal diameters and wall thickness consistent throughout the assembly.

The section of the inlet line from the manifold to the mud tank should be securely staked or weighted. It is important that the section running vertically adjacent to the mud tank wall be well secured in place.

Bull-plugged or targeted tees should be used for changes in piping direction.
Connections should be made using flanges or hammer unions. Material selection must be compatible with design criteria and special attention must be placed on elastomer components.

Welds should comply with IRP 1.9 Welding.

During winter, the line from the BOP stack to the mud-gas separator is to be filled with environmentally acceptable glycol water solution, or an equivalent water-soluble product. Diesel is not an acceptable alternative.

While the requirements for vent lines and vessels vary considerably for open bottom and enclosed mud gas separators, most inlet line requirements and specifications are identical and are outlined together in the recommended practices above.

For atmospheric pressure mud-gas separators, no valves or other mechanical restrictions should be permitted in the line, although inline glycol recovery drainage ports are acceptable providing they do not compromise system integrity or function.

For pressurized systems, valves or mechanical restrictions are permitted.

For pressurized systems, inlet line material selection will depend upon design condition relating to required pressures and temperature expectations. ASME section B31.3 may be used as a guideline to thickness requirements.

1.7.5. Vent Lines for Open Bottom Mud – Gas Separators

1.7.5.1. IRP Vent Lines for Open Bottom Mud – Gas Separators

Materials and fittings used in vent lines for open bottom mud gas separators should follow the recommendations as shown in Table 1.7.2.2.

Vent line sizing for open bottom mud gas separators should follow the schedule depicted in Table 1.7.2.1, with consideration to the fluid head level that is to be maintained. If desired and available, vent line sizes halfway between those shown for 1 m and 2 m of fluid head may be utilized in conjunction with 1.5 m of minimum fluid head.

Vent lines should slope down towards the flare pit and are to be securely staked or weighted. The section running adjacent to the mud tank wall should be rigidly secured in place.

Consideration should be given to wear and vibrational loading (fatigue) when vent lines are constructed from thin walled pipe.

Radiused bend fittings are acceptable for changes in pipe direction; however, wall thickness and internal diameters of lines and fittings should be consistent throughout the entire vent line.

Each open bottom mud-gas separator is to have a separate vent line extending to the flare pit.

Consideration should be given to the possibility of flashback and the potential ramifications of flashback for each specific installation. Such concerns are most prevalent when the largest vent line diameters are required and when low flow rates occur.
1.7.6. **REMOTE OPEN BOTTOM MUD – GAS SEPARATORS**

1.7.6.1. **IRP Remote Open Bottom Mud – Gas Separators**

Remote Open Bottom Mud-Gas Separators should be installed in a tank equipped with a dump gate and should be positioned near the rig mud tanks.

Gravity mud return line must be adequately sized to handle the highest anticipated mud return rate.

Figure 1.7.5.1 illustrates the suggested remote layout and sizing.

**Figure 1.7.5.1 Open Bottom Mud – Gas Separator: Remote Layout and Sizing**
**1.7.7. ENCLOSED MUD–GAS SEPARATORS: DESIGN SPECIFICATIONS**

**1.7.7.1. IRP Enclosed Mud – Gas Separators: Design Specifications**

An enclosed mud gas separator may be used in conjunction with an open bottom mud-gas separator on critical wells.

Additional information for pressure vessels is available in [IRP Volume 4 Well Testing and Fluid Handling](#).

Wall thickness should be determined by the maximum internal operating pressure required.

The design pressure should be at least 1.1 times the maximum allowable working pressure (MAWP) or 200 kPa, whichever is greater.

Standard pressure vessel stress calculations should be based upon ASME Section VIII Div. 1. A safety factor of 4.0 should be used for the maximum allowable stress value.

Joint efficiency values depend upon weld procedure and X-ray requirements must also be considered. (100% - 1.0, 90% - partial, 80% - no X-ray).

In addition, a minimum 3 mm should be added to design wall thickness for purposes of corrosion allowance.

As with open bottom separators, minimum thickness allowable should be 6 mm.

Vessels for atmospheric separators should be sized for gas flow rates at 100 kPa absolute pressure (0 kPa gauge pressure) at 15°C.

Vessels for pressurized separators using constant internal vessel pressure should be sized for gas flow rates at 80% of MAWP at 15°C.

Vessels for pressurized separators using variable internal pressure should be sized for gas flow rates at 80% of MAWP at 15°C.

The vapour space section between the inlet line and the vessel head tangent line should have a minimum height of 0.9 m.

The gas liquid disengagement section between the inlet line and the maximum internal fluid level should be at least 0.3 m.

The liquid section should consist of an active fluid zone between maximum and minimum fluid level, a buffer zone between minimum level and mud outlet, and sump zone below the mud outlet. Each of these three zones should be 0.3 m or more in height.

The mud outlet line should be capable of handling 1.5 m³/min of drilling fluid. A vortex breaker may be desirable in certain cases.

**1.7.8. ENCLOSED MUD–GAS SEPARATORS: REQUIRED COMPONENTS**

**1.7.8.1. IRP Enclosed Mud – Gas Separators: Required Components**

A fluid level control device (with manual override for internal fluid level control and independent fluid level indicator).

A mud outlet control valve with opening equal to mud outlet line diameter.
A mechanical control for atmospheric enclosed vessel or a pneumatic or electric control for pressurized vessels.

A minimum 76 mm diameter full opening clean out valve for solids removal. The valve should include position indicator and lock.

A reliable, easy to read, externally mounted, internal fluid level indicator is strongly recommended.

An accurate pressure gauge mounted on the vessel vapour space.

A 101.7 mm diameter or larger relief line (such as 152.4 mm) must be run to the pit and securely staked or weighted.

A quick opening inspection hatch should be installed according to UG 46 ASME Section VIII, Division I.

The separator support structure should be designed to safely support vessel filled completely with 2100 kg/m$^3$ drilling fluid to the overflow fluid level.

**1.7.9. ENCLOSED MUD – GAS SEPARATORS: FABRICATION AND OPERATING GUIDELINES**

**1.7.9.1. IRP Enclosed Mud – Gas Separators: Fabrication and Operating Guidelines**

Vessels used in unheated areas should be fabricated from low temperatures tough rated materials. Atmospheric enclosed vessels should be fabricated from materials listed in Table 1.7.2.2

Pressurized vessel materials will be required to meet ASME, Section VIII, Division I and NACE MR 01 75 (latest revision). Welding on pressurized separators should meet the Alberta Boiler and Pressure Vessel Code and shall be performed per ASME, Section IX, Division I.

Identification plates are required for pressure vessels by the local governing boiler inspector. Atmospheric tanks should contain a nameplate similar to that required for pressure vessels. Flow capability is generally not included on the nameplate of pressure vessels.

Enclosed separators should be accompanied by an operation and maintenance manual, which describes primary and manual operation, inspection, function testing and routine maintenance. Installation should be included along with a system schematic.

Drilling fluid outlet from atmospheric vessels should be directed to the sand trap or shaker box. Procedures for sour fluid returns have to be developed for each rig configuration.

Drilling fluid outlet pressurized mud gas separators should be directed to a secondary degasser (such as a vacuum degasser) to remove residual entrained gas.

Secondary degassers should be sized to handle full mud return rate anticipated. Separated gas must be directed away from the mud tank and work areas.

Fluid level control mechanisms should be function tested upon installation, when testing the choke manifold and prior to penetration of any critical zones.
After major kicks or kicks of extended duration, mud gas separator systems should be fully inspected. Any repair or replacement should conform to original requirements and should be documented by equipment owner.

**1.7.10. Vent Lines for Enclosed Separators**

**1.7.10.1. IRP Vent Lines for Enclosed Separators**

Materials and fittings used in vent lines for enclosed mud gas separators should follow the recommendations as shown in Table 1.7.2.2

Each enclosed separator must have a separate vent line extending to the flare pit.

Consideration should be given to the possibility of flashback and the potential ramifications of flashback for each specific installation, particularly at low flow rates.

Vent lines for both types of enclosed separators (atmospheric and pressurized) should be sized to provide a maximum back pressure equivalent to 70 % of vessel MAWP assuming isothermal flow at 15 °C. In no case should the vent line be less than 101 mm in diameter.

Pressurized separators which operate under constant internal pressure utilize a control valve located in the vent line. This variety is not recommended.

**1.7.11. Reference List**

ASME, Pressure Vessels 1986, Section VIII, Division 1, New York, New York.

NACE, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, 1984 Editorial Revision, MR 01 75, Houston, Texas.

1.8. **DRILL STRING DESIGN AND METALLURGY**

1.8.1. **ACKNOWLEDGEMENT AND DISCLAIMER**

The Drill String Pipe Design and Metallurgy IRP's have been developed recognizing the need for drill pipe integrity during both routine drilling conditions and those conditions which could be encountered during well control operations.

Qualification of existing drill pipe is addressed as well as minimum specifications for new SS75, SS95 and SS105 drill pipe tube and tool joints. Conventional inspection and documentation guidelines for critical drilling are included.

It should be emphasized that these recommended practices should be periodically updated with advances in technology. After such on going improvements in techniques and technology are field proven, they should be incorporated into critical drilling programs to further reduce the possibility of drill string failure.

The "drillstring" includes all the components below the Kelley Saver Sub to the Bottom Hole Assembly (drill collars) including:

- Pup Joints
- Heavy Weight Drill Pipe
- Stabbing Valves, Inside BOP, Kelly cock, Kelly saver subs

Drill collars and Bottom Hole Assembly are not included since:

- These components are at the bottom of the drill string and so if they failed during drilling, it would have little negative impact on well control capability.
- During tripping, these components are not highly stressed and so would likely not fail.

1.8.2. **DRILL PIPE GRADES**

This IRP refers to several different grades of drill pipe based on their metallurgical specification:

- API Grade E75, X95, G105, S135
- Hardness Tested (as specified in this IRP) API E, X, G (referred to HE, HX, HG)
- New sour service drill pipe (as specified in this IRP) SS75, SS95, SS105
1.8.2.1. IRP Drill Pipe Grade: Use Specifications

Standard AP1 grade pipe, unless hardness tested, should not be used for Critical Sour Wells. The only exception would be for S135 (see IRP 1.8.2.2 IRP Drill Pipe Grade: Use Preference 2).

Hardness Tested HE, HX, HG may be used until January 1, 2010, but consideration should be given to using SS grade pipe.

All new drill pipe manufactured (weld date) after January 1, 2002 and used on Critical Sour Wells must meet SS pipe specifications.

1.8.2.2. IRP Drill Pipe Grade: Use Preference

Grades HX and HG drill pipe should only be used if heavy wall premium Grade HE drill pipe does not meet the minimum overpull criteria.

API Grade S-135 pipe may be used, but not unless absolutely necessary, when heavy wall Grade HG is insufficient for the tensile or torque loading. Strict exposure control is mandatory (since API Grade S 135 is highly susceptible to both H₂S and chloride-induced failure).

1.8.3. Drill String Over Pull Design Considerations

Grades HX 95 and HG 105 should only be used if the over pull margin of heavy wall HE is insufficient.

The final margin of over pull at surface should be somewhat higher than the margin at the crossover between two grades or two weights.

Desirable over pull margins are in the order of 30,000 - 50,000 daN. Heavy wall Grade E refers to 25.6 lb/ft (37.4 daN/m) and 20.0 lb/ft (29.2 daN/m) for the 5" (127 mm) and 4½” (114.3 mm) sizes, respectively.

Heavy wall Grade SS 95 or SS105 is desirable for the uppermost section in even deeper critical wells, when the tensile capability of regular weight Grade SS 95, SS105 or heavy wall Grade SS 75 is insufficient.

Moving to a stronger grade or weight of drill pipe will usually be required based on insufficient over pull tensile margin at surface, as opposed to insufficient torsion capability, which may be the limiting factor in certain deep, deviated wells.

Tensile Calculations: For drill string design purposes it is acceptable, at the operator's discretion, to utilize the force balance (i.e., pressure area) method of drill string design.

1.8.4. Drill Pipe Class / Tensile Rating

1.8.4.1. IRP Drill Pipe Class / Tensile Rating

Only premium class or better drill pipe is recommended for critical sour drilling. Premium Tensile Ratings are as per API RP 7G.

Tensile ratings for drill pipe can be increased to New Drill Pipe rating, for drill pipe design, if the pipe has been inspected for wear, and it is less than 10 % wall loss, as per API RP 7G.
However, in certain cases such as very shallow wells, engineering judgments with respect to anticipated drill string torque, internal and external pressure requirements, and lack of pipe wall defects may suggest acceptability of Class 2 drill pipe.

1.8.5. **EXPOSURE CONTROL**

1.8.5.1. **IRP Exposure Control**

Exposure control is recommended for all grades of drill pipe. When HX95, HG105 or S135 must be used, strict exposure control is mandatory.

Drill pipe exposure control is accomplished by several means.

- The drilling fluid density is maintained sufficiently high so that only drilled gas is permitted to enter the annulus.
- The pH of the mud (in a water-based system) is maintained above 10.0 to solubilize the sulphides.
- Scavengers are employed to treat out H₂S.
- The system may be treated with inhibitors to coat the tubulars and provide some protection against short term exposure to H₂S.

1.8.6. **HARDNESS TESTED API GRADE DRILL PIPE SPECIFICATION**

1.8.6.1. **IRP Hardness Tested Grade Drill Pipe Specification: HE, HX, HG**

All API E, X and G drill pipe not manufactured to SS specification, and without previous hardness documentation, must be evaluated for hardness level prior to initial use for critical sour gas drilling.

Hardness testing must be redone after any significant re-work (e.g., baking after H₂S exposure or tool joint rebuild).

Hardness testing will conform to API RP 5A5 Subsection 4.5 with the following additional requirements:

- Direct reading Rockwell "C" (HRC) scale is required for the drill pipe.
- Rockwell "C", Brinell, or Equotip devices satisfactory for the tool joints.
- A total of nine impressions per joint required; three each at the box, pin and mid tube. Hard banding, heat-affected zones and areas of cold working such as slip and tong marks should be avoided.
- Abnormally high readings should be confirmed with additional tests on the prepared surface. Readings less than HRC 20 will not normally require retesting.

Each joint passing the hardness criteria will be marked with a unique identifier, which avoids duplication within a pipe owner’s stock.
Table 1.8.5 – API Drill Pipe Hardness Maximum Hardness (Rockwell “C”) For HE, HX, and HG Drill Pipe

<table>
<thead>
<tr>
<th>API Grade</th>
<th>Box</th>
<th>Pin</th>
<th>Tube</th>
</tr>
</thead>
<tbody>
<tr>
<td>HE 75</td>
<td>38</td>
<td>38</td>
<td>27</td>
</tr>
<tr>
<td>HX 95</td>
<td>38</td>
<td>38</td>
<td>30</td>
</tr>
<tr>
<td>HG 105</td>
<td>38</td>
<td>38</td>
<td>32</td>
</tr>
</tbody>
</table>

Documentation and Reports:

Hardness inspection reports will include the following details:

- location, rig, and pipe owner
- inspection company, date(s), and inspector
- diameter, weight, grade, connection type, and pipe classification
- test equipment make and model
- calibration details each occurrence
- surface preparation technique (light filing or sanding)
- individual and average readings for pin, tube, and box for each joint
- summary indicating total number of joints inspected, total rejected, and rejection criteria

1.8.7. **SS Grade Drill Pipe Tube Specifications**

1.8.7.1. **IRP Specifications for SS Drill Pipe Tube**

SS grade drill pipe tube must meet the following specifications.

Mill certification shall be obtained for all material criteria stipulated herein, including hardness test results.

Inspection results and string refurbish should be documented and included with the drill string service history.

Suitability for continued sour service should be based on the above criteria and other pertinent factors at operator / contractor discretion.

1.8.7.2. **IRP Tensile Property Specifications for SS Drill Pipe Tube**

Tensile properties for SS grade drill pipe tube shall meet the limits listed in Table 1.8.6.2 SS Drill Pipe Tensile Properties.

Specified elongation shall be a minimum of 17%.

Testing frequency should be one specimen per heat per heat treat lot, or every 200 tubes, whichever is the more frequent.
Table 1.8.6.2 SS Drill Pipe Tensile Properties Mpa / Ksi

<table>
<thead>
<tr>
<th></th>
<th>SS75</th>
<th>SS95</th>
<th>SS105</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yield Strength</td>
<td>517 / 75</td>
<td>655 / 95</td>
<td>655 / 95</td>
</tr>
<tr>
<td>Ultimate Tensile</td>
<td>655 / 95</td>
<td>793 / 115</td>
<td>724 / 105</td>
</tr>
</tbody>
</table>

1.8.7.3. IRP Hardness Specifications for SS Drill Pipe Tube

Hardness specifications for SS drill pipe tube shall meet the limits listed in Table 1.8.6.3 SS Drill Pipe Hardness.

Hardness level is to be verified on a ring sample with 9 impressions in each of four quadrants. Hardness Testing will conform to API 5CT latest edition Through Wall Hardness Test figure and ASTM E 18 Standard Methods of Tests for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials.

Testing frequency should be one set per heat, per heat treat lot or every 200 tubes, whichever is the more frequent.

A minimum of one impression on each tube (Rockwell or Brinell) is required.

Table 1.8.6.3 SS Drill Pipe Hardness Rockwell “C” (HRC)

<table>
<thead>
<tr>
<th>Grade</th>
<th>Single Point Reading</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Maximum Average</td>
</tr>
<tr>
<td>SS75</td>
<td>22.0</td>
</tr>
<tr>
<td>SS95</td>
<td>25.0</td>
</tr>
<tr>
<td>SS105</td>
<td>28.0</td>
</tr>
</tbody>
</table>

1.8.7.4. IRP Toughness Specifications for SS Drill Pipe Tube

Toughness specification for SS Grade tube shall require the minimum longitudinal Charpy "V" notch impact, from a 3/4 size specimen at room temperature per ASTM E23 latest edition, as listed in Table 1.8.6.4 SS Drill Pipe Toughness.

Testing frequency should be one set of three specimens per heat, per heat treat lot or every 200 tubes; whichever is the more frequent.

Table: SS Drill Pipe Toughness – Minimum Single Value CHARPY "V"
### Table 1.8.6.4 SS Drill Pipe Toughness Minimum Single Valve Charpy “V”

<table>
<thead>
<tr>
<th>Grade</th>
<th>Minimum Joules</th>
<th>Minimum Ft. Lbs.</th>
</tr>
</thead>
<tbody>
<tr>
<td>SS75</td>
<td>70</td>
<td>/</td>
</tr>
<tr>
<td>SS95</td>
<td>80</td>
<td>/</td>
</tr>
<tr>
<td>SS105</td>
<td>80</td>
<td>/</td>
</tr>
</tbody>
</table>

### 1.8.7.5. IRP H₂S Resistance Specifications for SS Drill Pipe Tube

SS drill pipe shall have a demonstrated minimum threshold of 85 % of the specified minimum yield strength for 720 hours per NACE TM-01-77 (latest revision), Method A using Test Solution A.

Testing frequency should be one specimen per heat, per heat treat lot, or every 200 tubes, whichever is the more frequent.

If any heat has a failed specimen, two additional specimens from the same heat / heat treat lot are required as a retest. If either fail, the heat is unacceptable.

### 1.8.7.6. IRP Chemistry Specifications for SS Drill Pipe Tube

Recommended chemistry specifications for new SS tube should include the maximum and minimum weight per cent limits as listed in Table 1.8.6.6 Recommended SS Drill Pipe Chemistry.

For sulphur levels approaching the specified maximum, a manganese limit of 1.2 % maximum is recommended to avoid reduced SSC resistance and material toughness.

Additional micro alloys or processing materials may be utilized at manufacturer's discretion.

Alternative chemistries may be acceptable, but they must be reviewed and approved by a qualified technical expert.

### Table 1.8.6.6 Recommended SS Drill Pipe Chemistry Weight per Cent

<table>
<thead>
<tr>
<th></th>
<th>SS75</th>
<th></th>
<th>SS95</th>
<th></th>
<th>SS105</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Min</td>
<td>Max</td>
<td>Min</td>
<td>Max</td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>Carbon</td>
<td>-</td>
<td>0.38</td>
<td>0.25</td>
<td>0.35</td>
<td>0.25</td>
<td>0.35</td>
</tr>
<tr>
<td>Manganese</td>
<td>-</td>
<td>1.60</td>
<td>0.40</td>
<td>1.00</td>
<td>0.40</td>
<td>1.00</td>
</tr>
<tr>
<td>Chromium</td>
<td>-</td>
<td>-</td>
<td>0.90</td>
<td>1.30</td>
<td>0.90</td>
<td>1.30</td>
</tr>
<tr>
<td>Molybdenum</td>
<td>-</td>
<td>-</td>
<td>0.30</td>
<td>0.60</td>
<td>0.30</td>
<td>0.60</td>
</tr>
<tr>
<td>Sulphur</td>
<td>-</td>
<td>0.010</td>
<td>-</td>
<td>0.010</td>
<td>-</td>
<td>0.010</td>
</tr>
<tr>
<td>Phosphorous</td>
<td>-</td>
<td>0.015</td>
<td>-</td>
<td>0.015</td>
<td>-</td>
<td>0.015</td>
</tr>
</tbody>
</table>

### 1.8.7.7. IRP SS Drill Pipe Tube Transformation and Grain Size

Minimum transformation to martensite after quenching should be 90 % across the full wall of the SS 95 and SS-105 drill pipe wall.

Grain size specification shall be six or finer per ASTM E112 (latest revision).
1.8.7.8. **IRP Tube / Tool Joint Transition**

The transition from the drill pipe ID to the standard upset ID should occur over a sufficient length as to minimize drill pipe tube fatigue failures adjacent to the upset area.

This minimum transition should be approximately 76.2 mm (3") for standard wall thickness drill pipe and commensurately longer for higher strength and weight pipe so that the taper angle remains relatively unchanged.

1.8.7.9. **IRP Drill Pipe Identification**

All drill pipe conforming to SS specifications must be marked with a unique identifier that is visible from the driller’s location.

A suggested method is shown in Figure 1.8.6.9 Suggested Drill Pipe Identification.

**Figure 1.8.6.9 Figure: Suggested Drill Pipe Identification**

![Diagram of drill pipe identification](image)

1.8.8. **SS Grade Tool Joint Specification**

1.8.8.1. **IRP Specifications for SS Tool Joints**

Tool Joints used on all grades of SS tube must meet the following specifications; there is only one grade of SS Tool Joint.

It is recommended that mill certification be obtained for all material criteria stipulated herein, including hardness test results.
Inspection results and string refurbish should be documented and included with the drill string service history.

Suitability for continued sour service should be based on the above criteria and other pertinent factors at operator / contractor discretion.

**Note** These specifications apply to all SS tool joints using API or non-API thread forms.

### 1.8.8.2. IRP Tensile Property Specifications for SS Tool Joints

Tensile properties for SS grade tool joints shall meet the limits listed in Table 1.8.7.2 SS Tool Joint Tensile Properties

Specified elongation shall be a minimum of 15 %.

Specified reduction in area shall be a minimum of 35 %.

Testing frequency should be one specimen per heat per heat treat lot or every 200 tool joint box/pin set, whichever is the more frequent.

**Table 1.8.7.2 SS Tool Joint Tensile Properties Mpa/Ksi**

<table>
<thead>
<tr>
<th></th>
<th>Minimum</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Yield Strength</strong></td>
<td>758/110</td>
<td>862/125</td>
</tr>
<tr>
<td><strong>Ultimate Strength Tensile</strong></td>
<td>862/125</td>
<td>1000/145</td>
</tr>
</tbody>
</table>

### 1.8.8.3. IRP Dimensional and Torsion Specifications for SS Tool Joints

Tool joint design, API and non-API, must be evaluated for torsional requirements.

For API thread forms, in conjunction with reduced yield strength, the tool joint pin ID and/or box OD should be modified to maintain tensile and, in particular, torsional strength, as listed in Table 1.8.7.3 Recommended Tool Joint Dimensions And Resulting Strengths For Typical Connections.

**Table 1.8.7.3.1 SS75 Drill Pipe Recommended SS Tool Joint Dimensions and Resulting Strengths for Typical Connections.**

<table>
<thead>
<tr>
<th>Pipe Size</th>
<th>Connecti on</th>
<th>Nom Weight</th>
<th>Outside Diam</th>
<th>Inside Diam</th>
<th>Tensile</th>
<th>Torsional</th>
</tr>
</thead>
<tbody>
<tr>
<td>In. (mm)</td>
<td>Lb/FT (kg/m)</td>
<td>Inches (mm)</td>
<td>Inches (mm)</td>
<td>Lbs (kN)</td>
<td>Pipe</td>
<td>Tool JT</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3 - ½ (88.9)</td>
<td>NC38 (3 - ½ IF)</td>
<td>13.30 (19.79)</td>
<td>5.000 (127)</td>
<td>2.563 (65.09)</td>
<td>271,600 (1,200)</td>
<td>18,600 (25,200)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>15.50 (23.07)</td>
<td>5.000 (127)</td>
<td>2.438 (61.91)</td>
<td>322,800 (1,400)</td>
<td>21,100 (28,600)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC38 (3 - ½ IF)</td>
<td>14.00 (20.83)</td>
<td>5.000 (127)</td>
<td>2.563 (65.09)</td>
<td>285,400 (1,300)</td>
<td>18,400 (25,000)</td>
</tr>
<tr>
<td>4</td>
<td>NC40</td>
<td>15.70</td>
<td>5.000</td>
<td>2.438</td>
<td>324,100</td>
<td>25,800</td>
</tr>
<tr>
<td>Pipe Size</td>
<td>Connection</td>
<td>Nom Weight Lb/Ft (kg/m)</td>
<td>Outside Diam Inches (mm)</td>
<td>Inside Diam Inches (mm)</td>
<td>Tensile Lbs (kN)</td>
<td>Torsional Ft-lb (N-m)</td>
</tr>
<tr>
<td>-----------</td>
<td>------------</td>
<td>-------------------------</td>
<td>--------------------------</td>
<td>------------------------</td>
<td>-----------------</td>
<td>----------------------</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC40 (4 FH)</td>
<td>14.00 (20.83)</td>
<td>5.000 (127)</td>
<td>2.688 (68.28)</td>
<td>285,400 (1,300)</td>
<td>711,500 (964,600)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC40 (4 FH)</td>
<td>15.70 (23.36)</td>
<td>5.250 (133.35)</td>
<td>2.563 (65.09)</td>
<td>324,100 (1,400)</td>
<td>768,200 (1,041,500)</td>
</tr>
<tr>
<td>4 – ½ (114.3)</td>
<td>NC46 (4 – ½ XH)</td>
<td>16.60 (24.70)</td>
<td>6.250 (158.75)</td>
<td>3.000 (76.2)</td>
<td>330,600 (1,500)</td>
<td>961,100 (1,303,000)</td>
</tr>
<tr>
<td>4 – ½ (114.3)</td>
<td>NC46 (4 – ½ XH)</td>
<td>20.00 (29.76)</td>
<td>6.250 (158.75)</td>
<td>2.750 (69.85)</td>
<td>412,400 (1,800)</td>
<td>1,085,300 (1,471,400)</td>
</tr>
<tr>
<td>5 (127)</td>
<td>NC50 (4 – ½ IF)</td>
<td>19.50 (29.02)</td>
<td>6.375 (161.93)</td>
<td>3.500 (88.9)</td>
<td>395,600 (1,800)</td>
<td>1,017,400 (1,379,500)</td>
</tr>
<tr>
<td>5 (127)</td>
<td>NC50 (4 – ½ IF)</td>
<td>25.60 (38.10)</td>
<td>6.500 (165.1)</td>
<td>3.250 (82.55)</td>
<td>530,100 (2,400)</td>
<td>1,163,200 (1,577,100)</td>
</tr>
<tr>
<td>3 – ½ (88.9)</td>
<td>NC38 (3 – ½ IF)</td>
<td>13.30 (19.79)</td>
<td>5.000 (127)</td>
<td>2.438 (61.91)</td>
<td>344,000 (1,500)</td>
<td>648,900 (879,700)</td>
</tr>
<tr>
<td>3 – ½ (88.9)</td>
<td>NC38 (3 – ½ IF)</td>
<td>15.50 (23.07)</td>
<td>5.000 (127)</td>
<td>2.125 (53.25)</td>
<td>408,800 (1,800)</td>
<td>772,200 (1,047,000)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC38 (3 – ½ IF)</td>
<td>14.00 (20.83)</td>
<td>5.000 (127)</td>
<td>2.563 (65.09)</td>
<td>361,500 (1,600)</td>
<td>594,800 (806,500)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC40 (4 FH)</td>
<td>14.00 (20.83)</td>
<td>5.250 (133.35)</td>
<td>2.563 (65.09)</td>
<td>361,500 (1,600)</td>
<td>768,200 (1,041,500)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC40 (4 FH)</td>
<td>15.70 (23.36)</td>
<td>5.250 (133.35)</td>
<td>2.438 (61.91)</td>
<td>410,500 (1,800)</td>
<td>648,900 (879,700)</td>
</tr>
<tr>
<td>4 – ½ (114.3)</td>
<td>NC46 (4 – ½ XH)</td>
<td>16.60 (24.70)</td>
<td>6.250 (158.75)</td>
<td>2.750 (69.85)</td>
<td>418,700 (1,900)</td>
<td>1,085,300 (1,471,400)</td>
</tr>
<tr>
<td>4 – ½ (114.3)</td>
<td>NC46 (4 – ½ XH)</td>
<td>20.00 (29.76)</td>
<td>6.250 (158.75)</td>
<td>2.500 (63.50)</td>
<td>522,300 (2,300)</td>
<td>1,198,600 (1,625,100)</td>
</tr>
<tr>
<td>5 (127)</td>
<td>NC50 (4 – ½ IF)</td>
<td>19.50 (29.02)</td>
<td>6.625 (168.27)</td>
<td>3.250 (82.55)</td>
<td>501,100 (2,200)</td>
<td>1,163,200 (1,577,100)</td>
</tr>
<tr>
<td>5 (127)</td>
<td>NC50 (4 – ½ IF)</td>
<td>25.60 (38.10)</td>
<td>6.625 (168.27)</td>
<td>2.750 (69.85)</td>
<td>671,500 (3,000)</td>
<td>1,422,400 (1,928,500)</td>
</tr>
<tr>
<td>3 – ½ (88.9)</td>
<td>NC38 (3 – ½ IF)</td>
<td>13.30 (19.79)</td>
<td>5.000 (127)</td>
<td>2.125 (53.25)</td>
<td>380,200 (1,700)</td>
<td>348,900 (879,700)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC38 (3 – ½ IF)</td>
<td>14.00 (20.83)</td>
<td>5.000 (127)</td>
<td>2.563 (65.09)</td>
<td>399,500 (1,800)</td>
<td>594,800 (806,500)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC38 (3 – ½ IF)</td>
<td>15.70 (23.36)</td>
<td>5.000 (127)</td>
<td>2.438 (61.91)</td>
<td>453,800 (2,000)</td>
<td>648,900 (879,700)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC40 (4 FH)</td>
<td>14.00 (20.83)</td>
<td>5.250 (133.35)</td>
<td>2.563 (65.09)</td>
<td>399,500 (1,800)</td>
<td>768,200 (1,041,500)</td>
</tr>
<tr>
<td>4 (101.6)</td>
<td>NC40 (4 FH)</td>
<td>15.70 (23.36)</td>
<td>5.250 (133.35)</td>
<td>2.438 (61.91)</td>
<td>453,800 (2,000)</td>
<td>822,200 (1,114,700)</td>
</tr>
<tr>
<td>4 – ½ NC46</td>
<td>16.60</td>
<td>6.250</td>
<td>2.750</td>
<td>462,800</td>
<td>1,085,300</td>
<td>43,100</td>
</tr>
<tr>
<td>Pipe Size</td>
<td>Connection</td>
<td>Nom Weight Lb/Ft (kg/m)</td>
<td>Outside Diam Inches (mm)</td>
<td>Inside Diam Inches (mm)</td>
<td>Tensile Lbs (kN)</td>
<td>Torsional Ft-lb (N-m)</td>
</tr>
<tr>
<td>-----------</td>
<td>------------</td>
<td>------------------------</td>
<td>--------------------------</td>
<td>-------------------------</td>
<td>-----------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>(114.3)</td>
<td>(4 – ½ XH)</td>
<td>(24.70) (158.75) (69.85)</td>
<td>(2,100) (1,471,400) (58,500)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>4 – ½ (114.3)</td>
<td>NC46 (4 – ½ XH)</td>
<td>20.00 (29.76) 6.250 (158.75) 2.500 (63.50) 577,300 (2,600) 1,198,600 (1,625,100) 51,700 (70,000) 45,200 (61,300)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 (127)</td>
<td>NC50 (4 – ½ IF)</td>
<td>19.50 (29.02) 6.625 (168.27) 3.250 (82.55) 553,800 (2,500) 1,163,200 (1,577,100) 57,600 (78,100) 46,900 (63,700)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 (127)</td>
<td>NC50 (4 – ½ IF)</td>
<td>25.60 (38.10) 6.625 (168.27) 2.750 (69.85) 742,200 (3,300) 1,422,400 (1,928,500) 73,200 (99,200) 58,100 (78,800)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 1.8.8.4. Hardness Specifications for SS Tool Joints

Hardness specification for SS tool joints shall be limited to a maximum average of HRC 30.0 with no single reading above 32.0 HRC.

Testing frequency should be one test traverse per heat per heat treat lot or every 200 tool joint box / pin set, whichever is the more frequent.

A test traverse shall consist of full length hardness traverses mid wall and near inner and outer surfaces on longitudinal strip type cross section sample.

In addition, one impression should be taken on every tool joint element (pin and box) prior to threading and hard banding.

Hardness Testing will conform to ASTM E 18 Standard Methods of Tests for Rockwell Hardness and Rockwell Superficial Hardness of Metallic Materials.

### 1.8.8.5. Toughness Specifications for SS Tool Joints

Toughness specification for SS tool joints should require a minimum average longitudinal Charpy "V" notch impact value of 90 joules (66 ft lb.) for a standard specimen at room temperature, per ASTM E23 98.

Toughness specification for SS drill pipe weldments between tube and tool joint shall require a minimum longitudinal Charpy "V" notch impact value of 27 Joules (20 ft lb.) at room temperature.

Testing frequency should be one set per heat, per heat treat lot or every 200 tool joint box / pin set, whichever is the more frequent.

### 1.8.8.6. H₂S Resistance Specifications for SS Tool Joints

H₂S resistance specification for SS tool joints shall include a demonstrated minimum threshold of 493 Mpa / 72 ksi (65 % of specified minimum yield strength) for 720 hours per NACE TM-01-77 (latest revision), Method A using Test Solution A.

Testing frequency should be one set per heat, per heat treat lot or every 200 tool joint box / pin set, whichever is the more frequent.
To be acceptable, any heat / heat treat lot with a failed specimen requires two additional specimens with no failures.

1.8.8.7. Chemistry Specifications for SS Tool Joints

Recommended chemistry specifications for new SS tool joints should include the maximum and minimum weight per cent limits as listed in Table 1.8.7.7 Recommended SS Tool Joint Chemistry.

Alternative chemistries may be acceptable, but they must be reviewed and approved by a qualified technical expert.

<table>
<thead>
<tr>
<th>Table 1.8.7.7 Recommended SS Tool Joint Chemistry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weight per Cent</td>
</tr>
<tr>
<td>Min</td>
</tr>
<tr>
<td>Carbon</td>
</tr>
<tr>
<td>Manganese</td>
</tr>
<tr>
<td>Chromium</td>
</tr>
<tr>
<td>Molybdenum</td>
</tr>
<tr>
<td>Sulphur</td>
</tr>
<tr>
<td>Phosphorous</td>
</tr>
</tbody>
</table>

1.8.8.8. SS Tool Joint Transformation and Grain Size

Minimum transformation to martensite after quenching should be 90% across the full wall.

Grain size specification shall be six or finer per ASTM E112 96.

1.8.8.9. SS Tool Joint Hard banding

Hard banding should be applied to tool joints in a carefully controlled manner.

The hard band groove should be of limited precut depth avoiding sharp shoulders and should be applied with preheat after final temper avoiding excessive innermost thread temperature.

The welding should be performed in an inert atmosphere and matrix hardness should be limited through appropriate filler material choice.

Recommended hard banding types include "casing friendly" smooth or flat ground surface varieties.

1.8.9. INSPECTION

1.8.9.1. IRP Inspection

Inspections must follow API RP 5A51 Sections 1 through 4.

Drill pipe should meet or exceed specifications from API RP 7G, Section 10 (Identification, Inspection and Classification of Drill Stem Components) for Premium Class Drill Pipe. Applicable sections are all subsections of 10.1 through 10.11.
Critical Sour Drilling

**Note** These inspections do not include the hardness testing specified in this IRP.

Frequency:
- Prior to the penetration of the critical zone, unless a recent inspection has been conducted on each pipe within 90 operating days or the operator can otherwise demonstrate that the pipe is satisfactory. (this does not include hardness testing).
- Timing of inspection is to be at operator’s / contractor’s discretion.

Documentation and Reports:
Inspection documentation and updates are the responsibility of the pipe owner. Such information is to be provided to the operator or governmental agencies upon request.

API inspections reports will include general information, inspection details, and a summary section:
- location, rig, and pipe owner
- inspection company, date(s), and inspector
- diameter, weight, grade, and connection type
- total number of joints inspected
- inspection summary
- classification

**1.8.10. DOWNHOLE FLOATS**

**1.8.10.1. IRP Downhole Floats**

In general, downhole floats are recommended for use in the string while drilling the critical zone. The suitability of utilizing a downhole float should be evaluated on a site-specific basis at the discretion of the operator and/or contractor.

Whenever blind shear rams are not installed, a drillstring float / internal BOP should be used unless a qualified technical expert evaluates the specific well conditions and recommends it is not required.

When flapper type floats are utilized, they should be ported to facilitate procurement of shut-in drill pipe pressure. The recommended opening size in the float is approximately 6 mm.

Downhole float should be made of H₂S resistant material meeting NACE MR 01-75.
Advantages and Disadvantages of Downhole Floats

The advantages and disadvantages of a downhole float should be considered for each critical well.

<table>
<thead>
<tr>
<th>Advantage</th>
<th>Disadvantage</th>
</tr>
</thead>
<tbody>
<tr>
<td>It maintains positive resistance to flow up the drill pipe during all phases of drilling and well control operations.</td>
<td>Potential drill pipe collapse</td>
</tr>
<tr>
<td>Reduced likelihood of plugging bit nozzles.</td>
<td>Aeration of drilling fluid</td>
</tr>
<tr>
<td>Floats are advantageous when water drilling, or when extreme overpressures are present.</td>
<td>Increased surge pressures which may induce lost circulation</td>
</tr>
<tr>
<td>Aeration of drilling fluid</td>
<td>The chances of hydraulic pipe sticking may increase and there may be difficulty in obtaining shut in drill pipe pressures during well control operations.</td>
</tr>
</tbody>
</table>

A second advantage is

With proper selection of downhole floats, however, and modification to trip speed and pipe fill practices, the disadvantages of downhole floats can be significantly reduced.

### 1.8.11. UPPER KELLY COCKS, LOWER KELLY COCKS AND STABBING VALVES

#### 1.8.11.1. IRP Upper Kelly Cocks, Lower Kelly Cocks and Stabbing Valves

Upper Kelly Cocks and Lower Kelly Cocks should be utilized in all critical wells.

**Note** for Top Drive rigs, the "lower Kelly cock" is a drillstring valve between the top drive quill and the first joint of drillpipe.

Kelly Cocks and Stabbing valves should be certified by the manufacturer as being able to be routinely opened with 7000 kPa below the valve. The direction for testing Kelly Cocks is recommended from below only. These valves should not be opened during field pressure tests.

Function tests and pressure tests of Kelly Cocks and Stabbing valves should be performed during BOP stack pressuring testing (see 1.14.3.1 IRP BOP Pressure Testing).

**Valve Bodies:**

- Tensile strength: equivalent to that of the tool joints in use.
- Metallurgical: Kelly Cocks and Stabbing valves shall be manufactured to conform with the requirements of the IRP 1.8.8 SS Grade Tool Joint Specification or with the requirements of NACE MR 01-75.
- Inspection: inspected as per drillpipe (IRP 1.8.9 Inspection)
Internal Working Parts: of Kelly Cocks, Stabbing Valves, and inside BOP's should be made of H₂S resistant material meeting NACE MR 01-75.

**Note**  
Current regulations regarding the use of stabbing valves, inside BOPs and associated subs are believed to be adequate. Proper equipment maintenance and placement on the rig floor is, of course, essential to properly prepare for any internal flow situation.

### 1.8.12. PUP JOINTS AND HEAVY WEIGHT DRILL PIPE

#### 1.8.12.1. Pup Joints and Heavy Weight Drill Pipe

In general, the bodies of drill string components (other than BHA) should conform to the specifications for drill pipe tube or tool joints.

Hardness tested material will be allowed until January 1, 2010, but after that SS material must be used.

The following are the material specification for the component bodies:

- Pup Joints: SS drill pipe specifications (tube and tool joint, IRP 1.8.7 SS Grade Drill Pipe Tube Specifications, 1.8.8 SS Grade Tool Joint Specification)
- Heavy Weight Drill Pipe: hardness tested tool joint specification (IRP 1.8.6 Hardness Tested API Grade Drill Pipe Specification)

Inspection: Pup Joints and Heavy Weight Drill Pipe as per drillpipe (IRP 1.8.9 Inspection)
1.9. **WELDING**

1.9.1. **SCOPE**

**Note** The Welding IRP guidelines have been developed with consideration for drilling activities and environment, recognizing the need for equipment integrity during both routine drilling conditions and those conditions which could be encountered during well control operations.

Pressure containing parts fabricated by welding shall be performed using guidelines stated herein. Weld Procedures are developed to ensure that the pressure containing welds will mitigate effects of exposure to H₂S.

The weldments shall include casing bowls, piping in manifolds of any equipment that is subjected to pressure.

Qualified personnel as mandated by provincial regulations must perform welding.

1.9.2. **APPLICABLE CODES**

Relevant codes for the development of weld procedures are:

- ASME Section IX Boiler and Pressure Vessel Code,
- API 6A Specification for Wellhead and Christmas Tree Equipment
- CSA Standard Z662-03 Oil and Gas Pipeline Systems
- ANSI B31.3 Process Piping

1.9.3. **WELDING PROCESS**

The selection of appropriate welding process is dependent on field conditions and how well the work area is protected from the elements. Shielded Metal Arc process is the preferred process for welding of casing bowls to casing.

For other welding, such as pipe in manifolds or any pressure containment fabrication, any process can be used provided the work area is well protected from the elements, and the work pieces can be easily manipulated.
1.9.4. **Welding Electrodes – Sour Service**

The selection of electrodes shall be dependent on matching mechanical properties of mating pieces. The weld procedure and subsequent tests will confirm appropriate selection. For welding of carbon steel and low alloy steel parts in sour service, electrodes must have less than 1% nickel content.

1.9.5. **Welding Procedure Specification**

A weld procedure specification (WPS) must be developed in accordance to ASME Section IX. This procedure shall include the essential and non-essential variables in the welding process. They include:

- Materials to be welded
- Filler material, root and cap
- Pre-heat
- Interpass temperature
- Post heat
- Shielding gas
- Welding speed
- Direction of welding
- Welding technique
- Mechanical tests to be conducted (yield, tensile, elongation, reduction in area)
- Charpy impacts as required
- Hardness Traverse test to be specified
- Inspection requirements
- Records

Requirements from API 6A and NACE MR0175/ISO 15156 Parts 1 and 2 must be included when writing the Weld Procedure Specification.

1.9.6. **Procedure Qualification Record**

To comply with the requirements of ASME Section IX, a Procedure Qualification Record (PQR) must be completed. Representative parts shall be assembled by welding.

Casing bowls can be substituted with wrought bars of equivalent dimensions, chemical composition, heat treatment, and mechanical properties. Typical materials used to manufacture casing bowls are AISI 4130 and AISI 4140, quenched and tempered with 414 MPa (60 ksi) minimum yield strength, 586 MPa (85 ksi) minimum tensile strength, charpy impacts at −46 °C (−50 °F), 22 HRC maximum hardness. Actual casing of representative size, material, grade and weight shall be used wherever possible.
For other welding, actual parts or representative materials of equivalent mechanical properties and similar chemical composition shall be used as test pieces.

Each change in essential variable requires a different PQR. Example of change in essential variable is the change in casing grade or material, change in weld process, change in filler material, shielding gas and so on. A PQR that does not contain charpy impact test cannot be used for welding where charpy impacts are required.

Fabricated assembly shall be subjected to post weld heat treatment. Tests will be conducted on the fabricated assembly in accordance with ASME Section IX. In addition, yield strength shall be included in the test, as well as charpy impacts and hardness traverse. The hardness traverse shall be conducted in accordance with ISO 15156 Part 2 to meet the stated maximum hardness criteria, (i.e., 22 HRC when the design stress does not exceed 0.67 SMYS.)

Data to be included in the PQR:

- MTR of test pieces
- Filler materials used
- Test results of fabricated assembly
- Yield, tensile, reduction in area, elongation
- Charpy impacts
- Hardness Traverse
- Bend test
- Welding variables
- Name of welder
- Shielding gas used
- Voltage/Amperage
- Welding speed
- Heat Input
- Record of pre heat
- Record of interpass temperature
- Record of post heat

For other welding, a similar process shall be adopted.
1.9.7. **Welder Qualification**

The welder that performs the welding in the development of the PQR is qualified to the Weld Procedure Specification (WPS). The welder must be qualified to perform pressure welding per provincial regulations. The welder must also be qualified to the weld procedure. The effective duration of the welder’s qualification to perform welding and to use the WPS is subject to provincial regulations.

1.9.8. **Field Welding**

The welder that performs welding in the field must ensure that:

- Correct WPS and PQR
- Valid welding qualification
- Valid procedure qualification record
- Electrodes are protected from dirt and moisture
- If welding is perform in darkness, adequate lighting is used
- Work area shall be adequately protected from the elements such as wind, moisture and dust
- Visual examination of welding surfaces and surrounding areas. Ensure no defects are visible.
- Ensure work pieces are cleaned and free of moisture, dirt and grease
- Counter weights, ground clamps and other temporary attachments should not be welded to the pipe or fittings
- For casing bowls, drilling fluid level shall be lowered to at least 600 mm below the weld line

1.9.9. **Pre-Heat**

The pre heat shall be applied to both pieces prior to welding as per WPS. Heating shall be accomplished by a suitable method, which would provide the required metal temperature, uniform metal temperature increase and temperature control. The use of electric resistance, or thematic processes are preferred. Use of propane or oxyacetylene under controlled conditions is also acceptable.

The pre-heat temperature should be tested with crayons, thermocouple pyrometers or other suitable methods to ensure that the required pre-heat temperature is obtained prior to, and maintained during the welding operation.

For casing bowls, immediately before welding commences the pre-heat temperature should be between 200 °C and 315 °C for a minimum distance of 100 mm on either side of the weld area. Special attention should be given to the thicker sections of the casing bowl in order to ensure uniform pre-heating.
1.9.10. **Interrupted Welding**

If welding is interrupted before completion, interpass temperature using adequate heat treatment shall be maintained on the work pieces. If interruption is for a prolonged period, work pieces shall be subjected to controlled cooling; to ensure there are no detrimental effects to the materials. This is accomplished by covering work pieces with heat insulation blankets.

Before welding is resumed, pre-heat temperature must be used.

1.9.11. **Post Heat**

Post heat is the heat treatment of the fabricated assembly after all welding is completed. It is the application of heat to the welded area at a specified temperature and for a specified duration in accordance to the WPS used. The WPS shall ensure that the weldment hardness is 22 HRC or less and that the mechanical properties of the weldment meet design requirements. Heat treatment temperature should be checked by the use of thermocouple pyrometers, or other suitable equipment to ensure that the proper heat treatment has been accomplished.

Confirmation that the assembly is adequately stress relieved is by hardness testing.

1.9.12. **Repair Welds**

All repair welds shall be performed with the appropriate WPS. The selection of WPS shall be based on the material and mechanical properties of the part to be repaired. The welder performing the repairs shall be a qualified pressure welder and qualified to the selected WPS.

1.9.13. **Product Hardness Test**

A surface hardness test shall be performed on the fabricated assembly after post heat is completed. Location of hardness test shall be at the weld metal, casing bowl heat-affected zone, casing heat-affected zone, and parent metal unaffected by welding. ASTM E10 or ASTM E18 can be used to perform the hardness test. The hardness recorded in the PQR shall be the basis for acceptance if the weld is not accessible for hardness testing. Such hardness test shall be recorded as part of the welding documentation and kept on file for the well. Maximum hardness for carbon and low alloy steel shall be 22 HRC or 237 HB.

1.9.14. **Product Pressure Test**

The fabricated assembly shall be pressure tested in accordance with appropriate codes that governs the part.

1.9.15. **Casing Bowl Pressure Test**

Casing bowl shall be pressure tested through the test port provided and by internal pressure. Test pressures shall be the lower of:

- 75 % of pipe collapse or burst and
- rated working pressure of the top flange.
Test media shall be either nitrogen or hydraulic oil or media not subject to freezing.

Pressure test shall be for a duration of 15 minutes for 2 cycles. Record of pressure test shall be part of welding record for the well.

After pressure test, as much of the fluid shall be purged from the cavity with compressed air or nitrogen.

1.9.16. **NON – DESTRUCTIVE TESTING**

Each weld shall be subject to non destructive testing.

Fabrication of casing bowls to surface casing shall be subjected to:

- Visual examination of both weld joints
- Surface NDE such as MPI or LPI

Other weldments shall be subjected to non destructive testing as required by ANSI B31.3 or CSA Z662-03. As a minimum, weldments shall be visually inspected to ensure welds are free of defects, verify dimensional accuracy, surface finish of weldment, weldment free of undercut, pock marks, overlaps or cracks.

Fabricated assemblies that are subject to cyclic loading must be examined by surface NDE such as MPI or LPI to ensure weldment and heat affected zone are free of surface cracks. Acceptance criteria shall be per ANSI B31.3 or CSA Z662-03.

1.9.17. **WELDING DOCUMENTATION**

Documentation of the welding performed and associated tests performed shall be recorded and filed for easy retrieval. As a minimum the record shall contain:

- Name of welder
- Certificate number of welder qualification to perform pressure weld
- Certificate number of welder qualification to weld procedure
- Date of weldment
- Location of well
- WPS and PQR used
- Pre heat temperature
- Post heat time and temperature
- Hardness test record
- Pressure test record
- Non destructive test results
- Name of person performing NDE
If there are any defects found during examination of the welds, a record of the repair shall also be included in the welding documentation.

1.9.18. **REFERENCE LIST**


1.10. DRILLING FLUIDS

1.10.1. SCOPE
The drilling fluid has many functions and properties, however the following are those especially important for a critical sour well:

- Fluid density: must provide enough hydraulic head to prevent a kick
- H$_2$S Scavenging Capacity: must be able to scavenge small amounts of H$_2$S that may enter the wellbore
- Rheological Properties: must be viscous enough to suspend weighting material, but not so viscous as to cause excessive swab / surge pressures
- Alkalinity: must be alkaline enough to suppress (buffer) the solubility of small amounts of H$_2$S that may enter the wellbore

Note These recommendations may be difficult to meet in a 100 % oil based system. This is probably only an issue in a high GOR (gas / oil ratio) critical sour oil well with a crude oil based drilling fluid.

Wellsite drilling fluid testing and monitoring practices, to ensure these properties are maintained, are described.

Equipment and material inventory requirements are given.

The requirement to have a qualified drilling fluid specialist at the wellsite while in the critical zone is also outlined.

1.10.2. FLUID DENSITY

1.10.2.1. IRP Minimum Drilling Fluid Density
Fluid density: the drilling fluid must provide enough hydraulic head to prevent a kick.

For wells shallower than 1500 m, the minimum drilling fluid density should be 100 kg/m$^3$ higher than that required to balance the estimated formation pressure.

For wells deeper than 1500 m, the drilling fluid density should provide a hydrostatic pressure that is a minimum 1500 kPa higher (overbalance) than the estimated formation pressure.

This density should be maintained immediately prior to entering the critical zone and while the critical zone is open.

A mud scale should be on site that will accurately measure the mud density.
1.10.2.2. **IRP Drilling Fluid Density Check: Wiper Trips**

As a check on the correct amount of overbalance, a 10 stand wiper trip should be made and bottoms up circulated prior to pulling out of the hole the first trip after penetrating the critical zone.

As well conditions warrant, additional wiper trips may be required.

1.10.3. **H₂S Scavenging**

**H₂S Scavenging: General**

H₂S Scavenging Capacity: the drilling fluid must be able to scavenge small amounts of H₂S that may enter the wellbore. Scavenging is the removal of soluble sulphides by a chemical reaction.

Although many drilling fluid systems have natural H₂S scavenging capacity, this is difficult to measure and maintain. Therefore H₂S Scavenging additives (H₂S Scavengers) must be used.

The initial addition of H₂S Scavenger can be based on a calculated scavenging capacity; however it is difficult to directly measure the actual scavenging capacity of the drilling fluid.

Soluble sulphides in the whole drilling fluid indicate that H₂S has entered the drilling fluid (both water based and oil based).

**Water Based Fluids:**

- Soluble sulphides can be measured in the filtrate (although not oil based fluids).
- When soluble sulphides are detected in the filtrate, it is an indication that the sulfide concentration in the drilling fluid has exceeded the scavenging capacity of the fluid.
- Scavenger should be added to reduce the soluble sulphides in the filtrate to zero.

Therefore, the ongoing treatment should be based on monitoring soluble sulphides in the filtrate when drilling with water based fluid and monitoring soluble sulphides in the whole mud when using oil based fluid.

1.10.3.1. **IRP H₂S Scavenger Pretreatment**

Prior to entering the critical zone, enough H₂S Scavenger should be added to provide a calculated scavenging capacity of 500 mg/l soluble sulphides.

**Note** No pretreatment may be considered for low complexity, low impact, and simple ERP wells.

1.10.3.2. **IRP H₂S Scavenger Maintenance: Soluble Sulphides**

Prior to becoming critical, monitor (IRP 1.10.3.3 IRP Soluble Sulphide Monitoring, 1.10.3.4 IRP Soluble Sulphide Monitoring) for soluble sulphides in the whole mud, both water based and oil based fluids.

**Water based fluids:**

- If soluble sulphides are in the whole mud, monitor for soluble sulphides in the filtrate.
• Add the appropriate amount of H\(_2\)S Scavenger to ensure there are no soluble sulphides in the filtrate.

• Oil Based Fluids:
  • Add the appropriate amount of H\(_2\)S Scavenger to ensure there are no soluble sulphides in the whole mud.

### 1.10.3.3. IRP Soluble Sulphide Monitoring: Hach Test (water based fluids only)

Hach tests apply to water based muds. They should be started 12 hours prior to penetration of the sour zone and run every hour thereafter while circulating.

Hach tests should also be run on bottoms up after trips or drilling breaks. Hach tests should be conducted using whole drilling fluid until soluble sulphides are detected. Thereafter the test should be conducted using filtrate or preferably the Garrett Gas Train.

Hach tests are typically done by the derrickman, and the tests must be recorded.

### 1.10.3.4. IRP Soluble Sulphide Monitoring: Garrett Gas Train Tests

Garrett Gas Train tests should be conducted on the whole drilling fluid three times a day while in the critical zone, and any time the Hach test indicates the presence of soluble sulphides.

When drilling with water based fluids, if soluble sulphides are detected in the whole drilling fluid, Garrett Gas Train tests should be conducted on the filtrate. When drilling with oil based fluids, conduct the modified Garrett Gas Train test on whole mud.

If soluble sulphides are detected in the filtrate of a water based fluid or in the whole oil based fluid, Garrett Gas Train tests should be conducted every two hours. (as per IRP 1.10.3.2 IRP H\(_2\)S Scavenger Maintenance: Soluble Sulphides add the appropriate amount of H\(_2\)S Scavenger to ensure there are no soluble sulphides in the filtrate).

When no soluble sulphides are detected in the filtrate of a water based mud or in the whole oil based mud, revert to testing whole drilling fluids three times per day.

Garrett Gas Train tests are typically done by the drilling fluid specialist.

A record of the soluble sulphide content of the drilling fluid must be maintained throughout the critical period.

### 1.10.4. Rheological Properties

#### 1.10.4.1. IRP Swab / Surge Pressure: Gel Strengths

In order to prevent high swab / surge pressures, the drilling fluid must not be too viscous. The best indicator of this property is gel strengths.

Ten second, ten minute, and thirty minute gel strengths should be regularly measured and recorded. They should not be progressive, as determined by drilling fluid specialist.

Ten minute gel strengths should not exceed 30 pascals.
1.10.4.2. **IRP Rheological Properties**

While in the critical zone, the drilling fluid rheological properties should be maintained so that weight material remains suspended and circulation can be established readily after tripping.

The drilling fluid specialist on location must conduct the appropriate tests and subsequent drilling fluid adjustments to ensure these properties are maintained.

1.10.5. **ALKALINITY**

Alkalinity: General

Alkalinity: the drilling fluid must be alkaline enough to suppress (buffer) the solubility of small amounts of H₂S that may enter the wellbore.

1.10.5.1. **IRP Alkalinity: pH Control**

Water based drilling fluids: the pH should be maintained at 10.5 or greater.

Oil based drilling fluids: excess lime concentration should be maintained above 20 kg/m³.

1.10.5.2. **IRP pH Monitoring**

Applicable to water based drilling fluids while critical.

A continuous pH monitoring system must be installed and located as close as possible to the flowline discharge of the drilling rig.

This monitoring unit must be equipped with an alarm which will indicate a drop in pH.

1.10.6. **EQUIPMENT AND PRACTICES**

1.10.6.1. **IRP Back-up Drilling Fluid Volumes**

While in the critical zone, the usable surface drilling fluid volume should be 100 % of the calculated volume of a gauge hole minus the drill string displacement.

If lost circulation occurs and the 100 % volume guideline is not maintained, drilling should be stopped until the guideline can be met.

The minimum amount of mud material inventory on location should provide enough time for replenishment from a nearby stock point.

1.10.6.2. **IRP Drilling Fluid Mixing System**

A mechanical mud agitator should be in the suction tanks and agitation should be provided in other compartments.

A minimum of two drilling fluid mixing systems (hopper, pump and piping) must be installed.

Each drilling fluid mixing system must be capable of mixing two sacks of barite per minute (80 kg/minute).

Each drilling fluid mixing system (minimum 80 kg/minute) must be independent of the drilling rig's circulating system.
A bulk delivery system (minimum 80 kg/minute) should be considered if the drilling fluid density is expected to be high or if remoteness and/or seasonal conditions dictate.

The rig's circulating system shall consist of a minimum of two mud pumps.

**1.10.6.3. IRP Drilling Fluid Material Inventory**

The minimum amount of drilling fluid maintenance material inventory on location should provide the ability to maintain the system to properties outlined in this IRP until the materials can be replenished from the nearest stock point.

If overpressured zones are to be encountered and the formation pressure is known, the amount of inventory on location should be enough to weight up to the formation pressure plus the required overbalance (IRP 1.10.2 Fluid Density).

There should be enough inventory of H$_2$S scavenger on location to provide the initial treatment plus provide an additional calculated scavenging capacity of 500 mg/l soluble scavenger capacity (IRP 1.10.4 Rheological Properties).

If lost circulation is expected or encountered, an appropriate inventory of Lost Circulation material should be maintained on location.

**1.10.6.4. IRP Gas Detector**

A total gas detection unit shall be installed prior to entering the critical zone.

While in the critical zone, the unit shall be continually monitored; which may include the use of alarms.

**1.10.6.5. IRP Drilling Fluid Specialist**

A qualified drilling fluid specialist shall be on location prior to drilling into, while drilling through, and at least 100 m below the critical sour formation or at any time there are soluble sulphides in the mud filtrate.

**1.10.6.6. IRP Suspension of Drilling Ahead**

If the properties of the mud deviate from the above recommendations, drilling should stop and the mud should be conditioned prior to drilling ahead or tripping.

If severe entrapped air / gas occurs or serious foaming occurs, drilling should not continue until the problem has been alleviated.

The above recommended mud properties should enable the critical zone to be drilled successfully. However, under specific circumstances, variations from these properties may be required as dictated by the qualified drilling fluid specialist on location.
1.11. **Kick Detection**

1.11.1. **Scope**
Kick detection equipment, procedures, and well control training requirements are specified by legislative requirements for all wells. This IRP outlines the additional kick detection equipment required for a critical sour well to improve these practices:

- Drilling fluid volume measurement
- Drilling fluid return flow indicator
- Trip tank fluid volume measurement
- Measuring Indirect indicators:
  - Electronic drilling parameter measurement
  - Driller's instrumentation
  - Mud gas logging

1.11.2. **Drilling Fluid Volume Measurement**

1.11.2.1. **IRP Mud Tank Volume Monitoring System**
A mud tank level monitoring system (e.g., Pit Volume Totalizer) that would meet the following specifications is required.

The system must be designed and installed so that it is capable of detecting a change of +1.0 m³ in total pit volume. In general, this means a probe must be installed in each active compartment.

A fluid level monitoring station with an alarm system must be located at or near the driller's position.

When drilling, the alarm must be set to detect a maximum change of +2.0 m³.

Continuous recording must be used to record the mud tank volumes (this may be part of the Electronic Drilling Recorder (EDR), see IRP 1.11.5 Monitoring Indirect Indicators).

The alarm system must include a visual indicator, which would come on automatically whenever the alarm is shut off. The indicator must effectively alert the driller both on the floor and in the doghouse.
1.11.3. **FLOW LINE FLOW SENSORS**

1.11.3.1. **IRP Flow line Flow Sensors**

A flow line flow sensor shall be installed which meets the following specifications. Capable of detecting a change of + 10% in the circulating rate, and setting an alarm if a change of 10% or greater is detected.

The alarm must be located at, or near, the driller's position.

The data must be recorded continuously on the EDR (see IRP 1.11.5.1).

The system must be checked once per tour while drilling by changing the pump SPM by 10%, ensuring the alarm sounds, and noting the corresponding flow reading. This will be recorded on the EDR (see IRP 1.11.5.1).

The alarm system must include a visual indicator, which would come on automatically whenever the alarm is shut off. The indicator must effectively alert the driller both on the floor and in the doghouse.

1.11.4. **TRIP TANKS**

1.11.4.1. **IRP Trip Tanks**

A trip tank is required which meets the following specifications.

A change of level of 25 mm equals a volume change of not more than 0.075 m$^3$. This equates to a maximum surface area of 3.0 m$^2$.

A minimum usable trip tank volume of 3.0 m$^3$.

If the trip tank requires refilling during the trip, the pipe pulling operation must be stopped while the tank is refilled.

The hole fill volume must be measured either by manual gauging of the trip tank or by reading a mechanical or automated monitoring system visible at the driller's position.

If a mechanical monitoring system is in use, the volume increments on the monitoring board must be 0.1 m$^3$.

If an electronic probe is used, the monitor's measurement increments must not exceed 0.0375 m$^3$ and the monitor must have readout to two decimal places.
1.11.5. MONITORING INDIRECT INDICATORS

1.11.5.1. IRP Electronic Drilling Recorder EDR

An Electronic Drilling Recorder EDR should be used to record:

- rate of penetration
- pump pressure / standpipe pressure
- pump strokes per minute / Flow rate
- hook load
- rotary table or top drive RPM
- rotary or top drive torque.
- Pit Volume
- Trip Tank Volume
- Mud return flow volume ("flow-show")
- Casing Annulus Pressure (choke manifold casing pressure)

Read-outs must be at the doghouse, wellsite supervisor's office, and rig manager's office.

The EDR primary data recording / storage computer must be more than 25 m from well centre.

The record must be kept for the entire well and be made available for inspection at the wellsite until rig release.

1.11.5.2. IRP Driller's Instrumentation

Indicators must be in operation for measuring hook load, pump pressure, and pump strokes per minute, and table or top drive torque. All such indicators must be visible from the driller's position.

A cumulative pump stroke counter should be required with readout at or near the driller's position. This might be included in the remote control system for a choke if in use. It may also be included in the EDR.

1.11.5.3. IRP Mud Gas Logging

A manned mud gas logging service should be used to provide continuous measurement of the gas content in the mud returns coming out the flow line (see IRP 1.10.6.4 Gas Detector).

An alarm system or intercom system should be in place to provide immediate communication from the operator of the mud gas detector to the driller in case a sudden increase in mud gas is noticed.
1.12. **WELLSITE SAFETY**

1.12.1. **Scope**

During any drilling operation, safety personnel and adequate safety equipment for all workers must be on site as per the appropriate regulations (e.g., as per the Occupational Health and Safety Act and Regulations).

The following recommendations address the unique conditions associated with critical sour gas H₂S drilling operations.

1.12.2. **GENERAL SAFETY REQUIREMENTS**

1.12.2.1. **IRP Pre-Job Orientation**

Prior to any work commencing on a critical sour well, a site-specific orientation must be reviewed with all on-site personnel involved in the operation. Documentation supporting this orientation must be kept at the wellsite.

Topics for review and discussion shall include, but not be limited to:

- Hazards involved, such as pressures, H₂S percentage, etc.
- Emergency preparedness
- Site specific equipment
- Communications
- Security
- Work status (as to critical/non-critical) and subsequent responsibilities

1.12.2.2. **IRP H₂S Training**

ALL personnel on the location while the critical sour zone is open must have the equivalent of H₂S Alive® certification.

Site access control personnel will deny access to anyone without certification (unless the visitor is accompanied at all times by a guide with the required certification).

1.12.2.3. **IRP Safety Supervision**

Prior to drilling into the critical sour zone, a minimum of two H₂S safety supervisors are required on a 24-hour basis, each working no more than 12-hour shift while on location.

Typical functions fulfilled by the safety supervisor include:

- Monitor compliance of all personnel with established safety policy and guidelines
- Inspect and maintain the safety equipment, monitors, and breathing apparatus. Conduct inspections of the safety equipment a minimum of twice per shift.
- Instruct personnel in the proper safety response to emergency situations, alarm conditions, and gas-to-surface conditions.
• Instruct personnel in the use of breathing apparatus including safe mask-up procedures and equipment limitations.
• Conduct practical drills to practice the use of breathing apparatus.
• Familiarize personnel with designated safe briefing areas and the safety equipment in each area.
• Instruct and supervise personnel in safe evacuation out of hazardous areas.
• Provide training to wellsite personnel in:
  o H₂S awareness
  o Site specific job hazards
  o Rescue procedures.
  o Personal Protective Equipment placement

1.12.2.4. IRP Site Access Control

Prior to drilling into the critical sour zone, site access control must be in place. Only authorized personnel will be allowed on the wellsite.

A record of all personnel on the wellsite must be maintained current at all times.

The number of personnel on the lease area during the critical sour drilling operation should be kept to a minimum, and restricted to those directly involved in the operation. Visitors must be briefed on emergency procedures before entering the lease area, and their visitation kept as short as possible.

1.12.3. H₂S Monitoring Equipment

1.12.3.1. Continuous H₂S Monitoring System

A continuous H₂S / LEL gas detection system is required while in the critical zone that meets the following specifications:

• A minimum of four sensors able to detect H₂S concentrations of 5 ppm or greater
• Audible and visual alarms near the driller's station.
• Alarms set at 10 ppm
• Sensor locations:
  • Shale shaker
  • Near the bell nipple
  • Rig floor
  • At the mud mixing unit

Qualified personnel must be on site to test and provide maintenance (typically the Safety Supervisor).
1.12.3.2. **IRP Portable H₂S Detection Devices**
One portable H₂S detection device is required while in the critical zone.

1.12.4. **BREATHING AIR EQUIPMENT**

1.12.4.1. **IRP Breathing Air Equipment**
A compressed breathing system shall be on location while drilling the critical zone.

The minimum basic equipment shall include:

- 2400 cu. ft. breathing air supply Emergency preparedness
- 2 - two-stage high pressure regulators
- 2 - six-outlet air header assemblies
- 8 - supplied air breathing apparatus c/w egress cylinders
- 8 - self-contained breathing apparatus
- 8 - spare 45 cu ft compressed breathing air cylinders
- 2 - 30 m x 10 mm I.D. special hose c/w quick couplers
- 6 - 30 m x 6 mm I.D. special hose c/w quick couplers
- 1 - 610 mm x 760 mm H₂S warning sign on tripod
- 2 - wind direction indicators

Prior to drilling into the critical zone, the safety equipment must be installed and ready for service, and crew members must be trained in the use of the equipment.
1.13. **WELLSITE PERSONNEL**

1.13.1. **Scope**

The Wellsite Personnel IRPs have been developed to address the issues regarding the supervisory and crew qualifications and requirements for conducting a critical sour drilling operation.

The roles and responsibilities for the operator's wellsite supervisor as well as the rig manager are outlined.

Experience levels and training/certification requirements for supervisors and crews are summarized.

1.13.2. **Responsibilities**

1.13.2.1. **IRP Operator’s Representative**

The operator will delegate a primary wellsite supervisor as having overall control in the chain of command.

The primary wellsite supervisor has the overall responsibility to his company for the well and for compliance with all regulations relating to the operation of the well.

He must establish a chain of command and a line of communication at the wellsite.

The primary wellsite supervisor must be onsite (or readily available can get to location within two hours) at all times.

1.13.2.2. **IRP Rig Contractor’s Representative**

The rig contractor’s representative has the responsibility to the operator’s representative for the operation of the rig during the drilling of the well which provides for a single chain of command for the well operation.

He is responsible to his company for the rig equipment and crew, and for compliance with all regulations relating to the operation of the rig.

1.13.2.3. **IRP Shared Responsibly**

The day-to-day operations on a lease are a shared responsibility between the contractor’s and operator’s representatives, but the ultimate responsibility for supervision of the well operation is assigned by the operator to the operator’s representative.

1.13.3. **Level of Supervision and Crew Requirements**

1.13.3.1. **IRP Wellsite Supervisors**

A 24 hour operation will require two supervisors, each working 12 hour shifts on site.

The primary wellsite supervisor must be delegated by the operator as having overall control in the chain of command.
1.13.3.2. IRP Rig Manager
The rig manager must readily available

1.13.3.3. IRP Drilling Crew
A minimum five man rig crew for each shift will be maintained while in the critical zone.

1.13.4. Minimum Qualifications
Operating company office supervisors

The demands placed on office supervisors (e.g., superintendents) of a critical sour drilling operation are very high due to the inherent complex nature of the operation, the increased risk factor, and the public impact of the operation.

Office Supervisors must therefore, have the technical, organizational and operational competence to meet these demands accordingly.

1.13.4.1. IRP Primary Wellsite Supervisor
The primary wellsite supervisor must be competent in the application of existing IRPs and Emergency Response Planning.

The Primary Wellsite Supervisor must have the following minimum experience levels:

- Five years operator's wellsite supervisory experience (or three years drilling engineering + two years wellsite supervisory experience)
- must have supervised a minimum of five sour drilling operations while operations were being conducted in the sour zone.

Since the complexity of a well generally increases with depth, the primary wellsite supervisor's previous sour well experience must have been on wells of similar complexity and depth when compared to the critical sour drilling operation they will be supervising.

Training / certification requirements:

- IRP 7 Standards for Wellsite Supervision of Drilling, Completions and Workovers, Section 7.6.3 Training Requirements
- Second Line BOP
- H₂S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry (Pre-Entry portion only)

The supervisor must be prepared to substantiate his/her work history. Time forward work is to be logged by the supervisor and supported by his/her direct supervisor of the operating company.
1.13.4.2. **IRP Second Wellsite Supervisor**

The Second Wellsite Supervisor must have the following minimum experience levels:

- Three years wellsite supervisory experience (operator or rig contractor) (or three years drilling engineering experience)
- Must have supervised a minimum of two sour drilling operations while operations were being conducted in the sour zone.

Training / certification requirements:

- IRP 7 Standards for Wellsite Supervision of Drilling, Completions and Workovers, Section 7.6.3 Training Requirements
- Second Line BOP
- H₂S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry (Pre-Entry portion only)

The supervisor must be prepared to substantiate his/her work history. Time forward work is to be logged by the operating supervisor and supported by his/her direct supervisor of the operating company.

1.13.4.3. **IRP Rig Manager**

The Rig Manager must have the following minimum experience levels

- Five years experience as a rig manager or driller.
- Must have been involved (as rig manager or driller) in five drilling operations while these wells were in the sour zone.

Training/certification requirements:

- Second Line BOP
- H₂S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry
- Fall Protection
1.13.4.4. **IRP Drilling Crew**

Each member must be competent to fully handle his / her individual responsibilities and to fully understand his/her responsibilities for the critical well control operation.

Drillers: must have a minimum of three years as a driller and / or derrick man, with experience in sour well operations. Must have First Line BOP certification.

Derrickmen / motorman: must have a minimum of three years rig experience, with experience in sour well operations.

Motorman / Floorhands: Must demonstrate crew competency requirements re BOP and Man-down drills as per IRP 1.14.4.1 IRP BOP Drills.

Training/certification requirements:

- H₂S Alive®
- First Aid
- WHMIS
- Confined Space Entry (at least 2 crew members)
- Fall Protection (Driller and Derrickman)

1.13.4.5. **IRP Safety Specialist**

Must have a minimum of two years as a field safety specialist, with experience in sour well operations.

Training / certification requirements:

- H₂S Alive®
- First Aid
- WHMIS
- TDG
- Confined Space Entry
- Fall Protection

1.13.5. **Certification and Training Course References**

The certification and training courses in this IRP refer to courses offered, or equivalent courses sanctioned by, Enform.
1.14. PRACTICES

1.14.1. SCOPE

The following are specific practices to be followed while drilling a critical sour well. They include:

- Rig inspections
- BOP / Casing andchoke manifold pressure testing
- BOP drills
- Tripping
- Drill stem testing
- Directional surveying
- Coring
- Fishing operations
- Logging
- Casing running and cementing

1.14.2. IRP RIG INSPECTION

A detailed inspection shall be conducted:

- Prior to drilling out the surface casing
- Prior to drilling out the intermediate casing
- Within the 24-hour period prior to penetrating the critical zone (if intermediate casing is set immediately above the critical zone, this inspection would coincide with the one above)
- The operator must notify the appropriate governmental agency 48 hours prior these inspections

In addition, the operator and the contractor shall conduct a weekly detailed rig inspection. An inspection check sheet shall be used, dated and signed by the operator’s wellsite supervisor and the rig manager, and retained.

The inspection must include:

- Pressure testing all equipment and casing in accordance the appropriate governmental requirements such as ERCB Directive 036: Drilling Blowout Prevention Requirements and Procedures.
1.14.3. **BOP, Casing and Choke Manifold Pressure Testing**

1.14.3.1. **IRP BOP Pressure Testing**

The BOP’s shall be pressure tested (see IRP 1.5.10.2 IRP Pressure Testing):

- At surface casing
- Prior to drilling our intermediate and production casing.
- While in the critical zone, every 30 days (minimum).

The pressure test shall be in accordance with the relevant governmental regulations.

1.14.3.2. **IRP Casing Pressure Testing**

The intermediate casing shall be pressure tested prior to drilling out.

While in the critical zone, the casing integrity shall be evaluated either through a pressure test, or appropriate casing wear log, every 30 days (minimum).

Consideration should be give for more frequent casing integrity evaluation if well conditions indicate excessive casing wear (e.g., high dog legs, rig misalignment, wear on wear bushing, metal contamination in drilling fluids, etc.)

1.14.3.3. **IRP Choke Manifold Pressure Testing**

The Choke manifold shall be pressure tested (see IRP 1.6.8.2 IRP Choke Manifold Pressure Testing Procedures):

- At surface casing
- Prior to drilling our intermediate and production casing
- After any use

The pressure test shall be in accordance with the relevant governmental regulations.

1.14.4. **BOP Drills**

1.14.4.1. **IRP BOP Drills**

Prior to entering the critical zone, each driller and crew must have an adequate understanding of:

- the correct operation of all the kick detection and monitoring equipment
- as well as their well control duties as required to control a kick while drilling, tripping and out of the hole
To confirm crew competence, a detailed BOP drill shall be conducted and documented by each rig crew:

- Prior to drilling out the surface casing
- Prior to drilling out the intermediate casing or prior to penetrating the critical zone
- The crews must demonstrate competence before proceeding
- At least two per week while in the critical zone

1.14.5. TRIPPING PRACTICES

1.14.5.1. IRP Trip Supervision

While in the critical zone, each trip must be preplanned by the operator’s wellsite supervisor and a pre-job safety meeting held with each crew participating in the trip.

While in the critical zone, a wellsite supervisor or rig manager with a Second Line BOP certification must be on duty during all trips.

1.14.5.2. IRP Hole Fill

The hole must be filled to surface after every 15 singles (maximum) of drill pipe, and after every three singles (maximum) of drill collars are pulled.

Weighted pills should be used to ensure the pipe pulls dry.

The practice of leaving the fluid level partially down the annulus in order to pull dry pipe is not allowed.

1.14.5.3. IRP Trip Record

A trip record must be made for every trip during the well.

Each trip record must be signed and dated by the operator's well site supervisor and the contractor's rig manager.

All trip records for the well must be kept and made available for inspection at the well site until rig release.

Each trip record must show the actual volume required each time the hole is filled as specified in IRP 1.14.5.2 IRP Hole Fill.

The cumulative total fill volume must also be recorded after each successive fill.

On the same page, the record must also show the theoretical value required at each fill point, plus the theoretical cumulative fill volumes.
1.14.5.4. **IRP Flow Checks**

Whenever any of the direct or indirect indicators of a kick are noticed, a flow check should be made. The well should be observed for 5 to 15 minutes to see if any flow occurs. Rotating the string slowly during this time should be considered.

Flow checks should be conducted:

- Tripping Out
- After pulling 5% of the drill pipe
- At the mid point depth of the wellbore
- Prior to pulling the first stand of drill collars
- Drill string out of hole
- Hole continuously monitored
- Tripping in
- Upon reaching the surface casing point
- At the mid point depth of the wellbore

Record the depth and time of all flow checks in the tour book.

As a check on the correct amount of overbalance, a 10 stand wiper trip should be made and bottoms up circulated prior to pulling out of the hole the first trip after penetrating the critical zone (also included in IRP 1.10.2.2 IRP Drilling Fluid Density Check: Wiper Trips)

1.14.6. **Drill Stem Testing**

Critical sour zones shall not be drill stem tested.

1.14.7. **Directional Surveying**

1.14.7.1. **IRP Directional Surveying**

The location of the wellbore must be known in order to allow a relief well to be drilled.

Prior to entering the critical zone, directional surveys (azimuth & inclination) are required at a maximum interval of 150 m when the wellbore is less than three degree inclination, or a maximum interval of 60 m when the wellbore is at an inclination greater than 3 deg.

This survey could be a wellbore survey (e.g., Multishot, gyro, or logging survey) prior to entering the critical zone.
1.14.8. **CORING**

1.14.8.1. **IRP Coring**

If coring in the critical zone:

- It is advisable to penetrate the upper porous interface prior to coring, however, if the interface must be cored, the ability to circulate above the core barrel must be available (e.g., a ported string).
- After tripping in the core barrel, bottoms up must be circulated and the wellbore confirmed dead prior to coring.
- After coring, a 10 stand wiper trip should be made and bottoms up circulated prior to pulling out of the hole for the core barrel.

1.14.9. **FISHING OPERATIONS**

1.14.9.1. **IRP Fishing Operations: Downhole Floats**

For normal drilling operations, IRP 1.8.10 Downhole Floats that a downhole float be used. However, for most trips made during fishing operations this option is not available due to fishing tool requirements, etc.

Extra care must be taken making these trips:

- Always circulate at least one bottoms up before tripping out.
- Extra diligence on tripping procedures: flow checks, hole fill, reduced tripping speed.
- Confirm crew competence of installing the stabbing valve.
- Consideration should be given to run a profile sub that would provide the option of setting a back pressure float, or plug, etc.
- The system shall be tested for pressure integrity, recognizing that, depending on the configuration, it may not be possible to test all connections.
- All components of the system must be secured properly to prevent excessive movement.


Through drill pipe wireline operations: A lubricator and associated bleed off system shall be used while running wireline tools inside drill pipe:

- All piping, valves, hoses, and manifolds should be checked for appropriate pressure rating and the materials must be suitable for sour service, as per the requirements for Choke Manifolds IRP 1.6 Choke Manifold.
- The complete system should be pressure rated to at least the working pressure of the BOP Stack.
1.14.9.3. IRP Fishing Operations: Retrieving Open Hole Logging Tools

For retrieving stuck open hole logging tools, it is recommended that the cut and thread technique not be used.

If considered, a full hazard and operability review should be done.

1.14.10. LOGGING
1.14.10.1. IRP Logging

Prior to open hole logging operations, the wellbore shall be confirmed to be in an overbalanced condition with no formation fluids in the wellbore. A wiper trip, as outlined in 1.10.2.2 IRP Drilling Fluid Density Check: Wiper Trips may be warranted.

A logging job pre plan review should be conducted with the logging contractor to identify any potential issues. Consideration should be given to the use of a lubricator. If a lubricator is used, it must conform to 1.14.9.2 IRP Fishing Operations: Through Drill Pipe Wireline Operations.

The wireline and tools should be treated with an appropriate inhibitor.

The hole must be monitored continuously for any indications of flow.

For drill pipe conveyed logging, the pipe to logging tool connector shall be sour service material.

1.14.11. CASING / LINER RUNNING
1.14.11.1. IRP Casing / Liner Running

Prior to running casing / liner across the sour zone, the wellbore shall be confirmed to be in an overbalanced condition with no formation fluids in the wellbore. A wiper trip, as outlined in 1.10.2.2 IRP Drilling Fluid Density Check: Wiper Trips, may be warranted.

A casing / liner running job pre plan review should be conducted, and a cementing job pre plan review should be conducted, to revise / confirm the original plan based on current well conditions.

After running and cementing casing, prior to removing the BOPs, one of the following should be done:

- The casing primary seal must be energized (i.e., run through the BOP), and/or
- The cement must provide a hydraulic seal across the sour zone (i.e., enough setting time elapsed for the cement to provide a hydraulic seal)

After running and cementing a liner, the pressure integrity of the liner lap should be tested prior to removing the BOPs. The casing should be cleaned to the top of the liner and a positive or negative pressure test conducted.

Consideration can be given to changing BOP rams to casing rams, depending on casing design. If casing rams are not used, there must be the appropriate crossovers from casing to drill pipe readily available.
1.14.12. **REVIEWS AND SAFETY MEETINGS**

1.14.12.1. **IRP Pre – Job Safety Meeting**

Immediately prior to starting critical sour drilling operations, a pre-job safety meeting must be conducted with **all** personnel on location.

It should include a review of the project plan.

1.14.12.2. **IRP Emergency Response Plan Meeting**

Immediately prior to drilling into the potential sour zones, an Emergency Response Plan (ERP) meeting must be conducted with **all** personnel involved with the ERP to review the ERP.

The operator, its contractors, board staff, and the government departments and agencies listed in the ERP should attend.

1.14.12.3. **IRP Safety / Operational Meetings**

When in critical zone, a short meeting must be conducted to review upcoming operations:

- prior to each shift or crew change,
- prior to a significant change in operations (e.g., tripping, logging, etc)

The meeting should include **ALL** personnel on location and should be documented on the tour sheet.

1.14.13. **WEAR BUSHING**

1.14.13.1. **IRP Wear Bushing**

Wear bushings should be run unless it can be demonstrated that there will be minimal potential for significant wear in the BOP / wellhead area (e.g., short duration of drilling with a downhole motor with minimal drill string rotation and trips).