CODE
FOR ELECTRICAL
INSTALLATIONS AT
OIL AND GAS FACILITIES

Established by the Multi-provincial Oil & Gas Code Committee and SaskPower
April 1999

Published by SaskPower
Preface

SaskPower is the body responsible for the development and maintenance of this Code. SaskPower uses the multi-provincial Oil and Gas Code Committee to provide expert advice and recommendations for amendments to the Code. SaskPower has endorsed this Third edition of the Oil and Gas Facilities Code in March, 2006. This third edition supersedes the previous edition published in 2002.

The Code was originally developed using previous Saskatchewan regulations as a guide. The most significant change from the regulation is the recognition of engineers’ involvement in classifying hazardous locations. Other changes include removing duplication with rules of the Canadian Electrical Code and adjusting the format of the document.

This Code is designed in the same format as the Canadian Electrical Code, Part I, hereinafter referred to as the CEC. The numbering system is equivalent to a separate Section of the CEC and this Code is intended to be supplementary to, or amending of, the CEC as indicated in the Scope. Appendix B19 is the equivalent of Appendix B in the CEC and formatted in the same way. Diagrams B19 form part of Appendix B19. Annex J19 is designed as an additional Annex to Appendix J of the CEC. Since this Code is supplementary to, or amending of, the CEC, all other Appendix B or Appendix J notes in the CEC are valid. Appendix C19 is the Organization and Rules of Procedure for the Committee on the Code for Electrical Installations at Oil and Gas Facilities approved by SaskPower. Appendix D19 is engineering guidelines for determining area classification.

Changes from the last edition of the Code are expressed with a triangle (Δ) where a requirement has been added or amended and a “no” symbol (∅) where requirements have been deleted.

Preamble

Some locations where flammable gases or vapours may occur are classified as Class I locations by Rule 18-004 of the CEC. The CEC further divides these locations into three Zones (Section 18) or two Divisions (Appendix J), depending on the frequency and duration of the occurrence of flammable quantities of these gases or vapours. Hazardous area classification is the process of determining which parts of a facility are hazardous and dividing them properly into zones or divisions to allow appropriate wiring methods and selection of electrical equipment. It is the responsibility of owners of facilities to ensure that the facilities are properly classified according to the definitions of the CEC. There are various industry-recommended practices that will help users in arriving at the proper area classification for their facilities. Some of these are referenced in Appendix B of the CEC and Appendix D19 of this code.

It is the responsibility of the person doing the area classification on behalf of the owner to ensure that the result is consistent with CEC requirements. This Code allows for professional engineers, with adequate related experience, to set the proper area classification of facilities and to document them under their seal. Without professional involvement, the specific area classifications outlined in this code shall be the minimum requirements. It remains the responsibility of the facility owner to determine that these requirements are adequate for each installation.
Acknowledgements

The contents of this publication have evolved from a long-standing tradition of industry involvement toward the development of oil and gas facilities requirements. Acknowledgement is given to all of the various stakeholders that have contributed their expert advice over the years. We also acknowledge the provinces of British Columbia, Alberta and Manitoba for their valuable input into this Code.

Following are membership lists of the Oil and Gas Code Committee as of June 2006.

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<td>Electrical Technical Council Alberta</td>
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<td>Rene Leduc (Secretary)</td>
<td>Designers and Engineers</td>
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Section 19 – Oil and Gas Facilities

Scope

19-000 Scope (see Appendix B19)

(1) This Code applies to electrical installations used in the search, transmission, or production of oil, natural gas and related hydrocarbons.

(2) This Code does not apply to electrical installations used in:
   (a) petroleum refineries;
   (b) petrochemical facilities;
   (c) gas distribution systems operated by a gas utility at a pressure of 700 kPa or less for the purpose of distributing gas to consumers in all or part of a municipality; and
   (d) fuel supply systems for equipment.

(3) This Code is supplementary to, or amendatory of, the requirements of the CEC.

(4) For additions, modification, renovations to, or operation and maintenance of existing facilities employing the Division system of classification for Class I locations, the continued use of the Division system of classification shall be permitted.

(5) Where the Division system of classification is used for Class I locations, as permitted by Subrule (4), the rules found in Annex J19 shall apply.

(6) Notwithstanding Subrule (5), equipment permitted in the Rules for installations in Class I Zone 2 locations shall also be permitted for installations in Class I Division 2 locations.

19-002 Interpretation

This Code and any standards referenced herein do not make or imply any assurance or guarantee by the authority adopting this Code with respect to life expectancy, durability or operating performance of equipment and materials referenced herein.

General

19-050 Grounding

A ground detection device is not required for the ungrounded secondary circuit of a supply transformer for a single downhole submersible oil pump.

19-052 Installation of Electrical Equipment (see Appendix B19)

(1) Flexible cord or portable power cable shall be permitted at drilling and servicing sites or oil and gas wells provided the flexible cord or portable power cable:
   (a) is suitable for exposure to oil and wet locations;
   (b) is supported, protected or located in a manner that prevents mechanical damage; and
   (c) otherwise complies with the requirements of CEC rules 18-122(a),(b),(c) and 18-176(a),(b),(c) for Class I locations.

(2) A lockable switch in the control circuit of the motor contactor for DC traction motors on drilling and servicing rigs shall be permitted to be used as the disconnecting means required by Section 28 of the CEC where the switch is located at the motor contactor.
(3) Lighting fixtures and portable equipment shall be supported independently of the cord and protected from mechanical injury by guards or equivalent means.

(4) A combination motor controller shall be permitted to be used as service equipment for a single oil well pump.

Classification of Oil and Gas Facilities

Δ 19-100 Hazardous Area Classification (see Appendices B19 and D19)

(1) Classification of hazardous locations established and documented by a professional engineer under the engineer’s seal and signature shall be the area classification.

(2) Where a facility has not been classified in accordance with Subrule (1), or evidence of an engineer’s involvement is not satisfactory to the inspection authority having jurisdiction, Rules 19-102 to 19-108 shall be the minimum requirement.

19-102 Common Classifications for Oil and Gas Facilities (see Appendix B19)

(1) The following are Class I, Zone 0 hazardous locations:

(a) the vapour space inside enclosed vessels or tanks containing a substance capable of producing an explosive gas atmosphere;
(b) the area within 0.5 m around an atmospheric vent venting from a Zone 0 area;
(c) a minimum area of 0.5 m around an equipment process vent; and
(d) the area within 0.15 m around an instrument or control device vent.

(2) The following are Class I, Zone 1 hazardous locations:

(a) the interior of buildings or enclosures housing tanks, pumps, valves, flanges or other equipment that is a potential source of leakage of flammable liquid, gas or vapour, except shed type enclosures shall be permitted to be Class I Zone 2 hazardous locations when open on 3 sides from grade to roof level and roof ventilators are provided where lighter-than-air gases may accumulate;
(b) the interior of buildings or enclosures, any part of which is located in a Class I, Zone 1 hazardous location, unless the buildings or enclosures are separated from the classified area by a vapour-tight barrier;
(c) any pit, depression or area below grade in a Class I, Zone 2 hazardous location where flammable liquids or flammable heavier-than-air gases and vapours may accumulate;
(d) the area within 1.5 m of a tool launcher/receiver opening or other similar facility;
(e) the area around atmospheric vents:
   (i) for 1.5 m when venting from a Zone 1 area; or
   (ii) between 0.5 m and 1.5 m when venting from a Zone 0 area;
(f) a minimum area of between 0.5 m and 1.5 m around an equipment process vent; and
(g) the area between 0.15 m and 0.5 m around an instrument or control device vent.

(3) The following are Class I, Zone 2 hazardous locations:

(a) outdoor or unenclosed areas within 3 m in any direction of a potential source of leakage of flammable liquid, gas or vapour;
(b) outdoor areas within 3 m of the outer confines of buildings or enclosures that are Class 1, Zone 1 hazardous locations, plus an additional horizontal distance of 4.5 m to a height of 600 mm above grade level where flammable liquids or flammable heavier-than-air gases and vapours may accumulate, unless the outer confines of the building are vapour-tight;

(c) the area within 3 m in any direction of any flammable gas or liquid storage vessel or tank and, where flammable liquids or flammable heavier-than-air gases and vapours may accumulate:

(i) an additional horizontal distance of 4.5 m to a height of 600 mm above grade level, or

(ii) when a dike is provided, the area within the perimeter and extending up to the top of the dike;

(d) the interior of buildings or enclosures, any part of which is located in a Class 1, Zone 2 hazardous location, unless the buildings or enclosures are separated from the classified area by a vapour-tight barrier;

(e) the area between 1.5 m and 3 m of a tool launcher/receiver opening or other similar facility;

(f) the area around atmospheric vents:

(i) for 3 m when venting from a Zone 2 area; or

(ii) between 1.5 m and 3 m when venting from a Zone 1 or Zone 0 area;

(g) a minimum area of between 1.5 m and 3 m around an equipment process vent; and

(h) the area between 0.5 m and 1 m around an instrument or control device vent.

19-104 Supplemental Classifications for Oil and Gas Drilling and Servicing Operations (see Appendix B19)

The following are Class 1, Zone 2 hazardous locations:

(a) the interior of buildings or enclosures housing tanks for normal well kill or circulating fluids where the fluids do not normally contain substances capable of creating an explosive gas atmosphere;

(b) the interior of buildings or enclosures housing open mixing or solids control apparatus;

(c) areas within 2 m of mud tanks and shale shakers where an enclosure is not provided;

(d) the entire area above the rig floor to the top of the enclosure, if provided, or to a height of 3 m, whichever is greater;

(e) the entire area under the rig floor or the area below the rig floor within 2 m horizontally of the centre of the well where the substructure is of the open type;

(f) the area within 2 m horizontally of the centre of the well and 3 m vertically of the uppermost well bore opening where a rig floor is not provided; and

(g) the area within the choke manifold building.
19-106 Supplemental Classifications for Oil and Gas Wells (see Appendix B19)

(1) The area within 1.5 m in any direction of a casing vent where explosive gas atmospheres are present under normal operation is a Class I, Zone 1 hazardous location.

(2) The following are Class I, Zone 2 hazardous locations:
   (a) the area within 1.5 m in any direction of a casing vent where explosive gas atmospheres are not present under normal operation;
   (b) the area between 1.5 m and 3 m in any direction of a casing vent where explosive gas atmospheres are present under normal operation; and
   (c) the area within 1.5 m horizontally of a junction box used for connection to a submersible pump downhole cable and extending from 1.5 m above the box to grade level, unless a wellhead feed-through-device is installed that prevents the migration of explosive gas atmospheres through the cable.

19-108 Supplemental Classifications for Water Flood and Disposal Systems (see Appendix B19)

The following are Class I, Zone 2 hazardous locations:
   (a) the interior of buildings or enclosures housing produced water injection wells; and
   (b) the interior of buildings in which water produced in conjunction with crude oil or fresh water containing gas is stored or processed or is subject to pumping operations.
Appendix B19

Notes on Rules

The notes and diagrams in this Appendix are for information and clarification purposes only and apply to the following rules:

<table>
<thead>
<tr>
<th>Rule</th>
<th>Note</th>
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<tr>
<td>19-000</td>
<td>Persons using this Code should be aware of other regulatory requirements such as in the areas of energy, occupational health &amp; safety and environment. See also Appendix J and notes on rules 18-000, 18-002 and 18-006 in Appendix B of the CEC. Where installations are not covered by this Code (19-000(2) (a) to (d)), sound engineering principles should be applied to determine if an installation should be classified in accordance with Rules 18-004 and 18-006 of the CEC.</td>
</tr>
<tr>
<td>19-052</td>
<td>This rule allows for additional situations not specifically addressed in the CEC. Users should give careful consideration to electrical installations where adverse conditions expose electrical equipment to a corrosive environment or to excessive moisture. The nature of activity at oil well servicing or drilling operations (i.e., equipment subject to splashing or direct streams of water), may require the use of “Type 4” enclosures, “Type TE” motors or equivalent. For additional information on IEC Ingress Protection (I.P.) designations, refer to IEC Standard 529 and CEC Appendix B note to rule 18-106(5).</td>
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<tr>
<td>19-052(1)</td>
<td>The use of flexible cord at drilling and servicing sites or oil and gas wells is intended to recognize situations where fixed wiring methods cannot provide the necessary degree of movement for fixed or mobile electrical equipment required to be frequently moved. It is not intended to be a substitute for fixed wiring. Excessive length, quantities and use of flexible cord or portable power cable is to be avoided.</td>
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<tr>
<td>19-052(4)</td>
<td>The use of a combination motor controller as service equipment for a single oil well pump may be appropriate where the utility has no meter or where the supply service requirements of the CEC permit “hot” metering installations. The supply authority should be consulted for metering requirements. When a small auxiliary load must also be supplied, a single feeder may be “tapped off” the combination motor controller in compliance with Rules 12-3032(2) &amp; 14-100 of the CEC. When adding an auxiliary load, consideration should be given to the main overcurrent device and the feeder or service conductors of the combination motor controller to ensure they are properly sized.</td>
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This rule recognizes the expertise of an engineer in classifying Oil and Gas facilities. The engineer must be experienced in determining area classifications for hazardous locations as outlined in Rule 18-006 of the CEC and knowledgeable in using industry-recognized standards and recommended practices. (See notes on rule 18-006 in Appendix B of the CEC.) Without engineering involvement, the requirements for classifying hazardous locations in rules 19-102 to 19-108 are the minimum requirements. When applying these minimum requirements, users are advised of their responsibility to ensure that they are adequate for the installation. Circumstances may dictate the need to exceed these rules to achieve an acceptable level of safety performance.

Rule 19-102 outlines area classifications for various installations that can be common to all types of oil and gas facilities. Rule 19-104 to 19-108 outline additional or supplemental area classifications for situations encountered at specific installations. The term “flammable” used throughout these rules with the words liquids, gases, and vapours should be taken in the context of the likelihood for these substances to create an explosive gas atmosphere. For more information on flammable liquids, gases and vapours see American Petroleum Institute RP500 & RP505 and NFPA Standard No. 30. To aid in the application of these rules, see the Diagrams B1 to B16.

To differentiate between different types of vents, the term is divided into three distinct categories: process equipment vents (e.g., pressure relief valves, blow-downs, etc.), instrument and control device vents (e.g., vents from gas actuated control devices, gas chromatograph vents, etc.) and atmospheric vents (e.g., building ridge vents, roof vents, tank vents, etc.). See American Petroleum Institute RP500 & RP505 for further information.

Classification requirements for process equipment vents are expressed in terms of absolute minimums. Criteria affecting classification of areas around process equipment vents in non-enclosed areas are diverse. Sound engineering judgement should be applied for specific cases, but in no case should the classification be less than those in the referenced rules and those shown in Diagram B16.

When we interpret the requirement of roof ventilators for shed type buildings or enclosures, we should take into consideration the shape of the roof. In contrast to a gabled roof, flat roofs would not normally allow a significant accumulation of lighter than-air-gases unless the fascia or roof edge prevented those gases
A risk analysis by the Canadian Association of Oilwell Drilling Contractors has determined that the probability of an explosive gas atmosphere occurring in a "doghouse" located outside the hazardous area of a drilling rig floor (with or without winter enclosures) is less than 1 hour in 100 years. The 1 hour in 100 years probability or less is the industry accepted norm for determining non-hazardous locations. For this reason, the "doghouse" located outside the hazardous area of the floor of a drilling rig is unclassified. Owners/operators may adopt policies that impose a more stringent wiring method as well as limit the type of equipment that can be used in the "doghouse".

Rule 19-108 can also assume situations where the water is likely to contain flammables due to process upset conditions but the associated equipment in the enclosure is vented to the outside of the enclosure. If equipment vents are not extended to the outside of the enclosed area, the enclosure should be classified Zone 1.

Rule 19-108 is not intended for situations where produced/processed water is likely to contain flammables on routine occasions or that could release sizeable quantities of flammables for extended periods. These types of situations call for proper engineering in accordance with Rule 19-100(1) or could alternatively be classified as a process facility in accordance with Rule 19-102.
Appendix B19 Diagrams

Diagram B1 – Service Rig
(Sub-structure and rig floor are not enclosed)
[See Rules 19-104(d) & (e)]

Hazardous Area Classification

- Zone 0
- Zone 1
- Zone 2

Grade Level

Rig Floor

3 m
2 m
Diagram B2 – Drilling Rig

[See Rule 19-104]

Hazardous Area Classification

- Zone 0
- Zone 1
- Zone 2

Plan View

- Rig Floor
- Sub-Structure
- Grade Level

- Accum. Bldg
- Boiler Bldg
- Fuel Tank
- Gen. Bldg
- Gen. Bldg
- Pump Bldg.
- Choke Manifold Bldg
- Mud Tank
- Mud Tank
- Mix & Solids Control

Dimensions:
- 3m
- 2m

Diagram shows the layout of a drilling rig with various hazardous areas and structures.
Diagram B3 – Mud Tank in a Non-enclosed Area
(Normal well kill or circulating fluids)
[See Rules 19-104(c)]

Diagram B4 – Mud Tank in a Enclosure
(Normal well kill or circulating fluids)
[See Rule 19-104(a)]
Diagram B5 – Mud Tank in an Enclosure
(Explosive gas atmospheres are present)
[See Rules 19-102(2)(a), (3)(b)]

Diagram B6 – Solids Control Apparatus in an Enclosure
(Mud-mix, De-sander, De-silter, etc.)
(Explosive gas atmospheres are not normally present)
[See Rule 19-104(b)]
Diagram B7 – Wellhead in an Enclosure
[See Rules 19-102(2)(a), (3)(b)]

Hazardous Area Classification

- Zone 0
- Zone 1
- Zone 2

Diagram B8 – Junction Box for Submersible Pumps
(Adequately ventilated area)
[See Rules 19-106(2)(c)]
Diagram B9 – Enclosed Area Adjacent to a Classified Area
[See Rules 19-102(2)(b) & (3)(d)]

Hazardous Area Classification

<table>
<thead>
<tr>
<th>Zone 0</th>
<th>Zone 1</th>
<th>Zone 2</th>
</tr>
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Source

Area classified due to source outside enclosed area

Enclosed Area

Vapour Tight Barriers

Diagram B10 – Tool Launching or Receiving Installation
(Adequately ventilated)
[See Rules 19-102(2)(d) & (3)(e)]

1.5m

1.5m
Diagram B11 – Typical Wellhead
[See Rules 19-102(2)(c), (3)(a) and 19-106(1), (2)(a) & (b)]

Hazardous Area Classification

- Zone 0
- Zone 1
- Zone 2

This area may be classified Zone 1 or Zone 2
[see 19-106 (1) & (2)(a & b)]

Diagram B12 – Valves, Pumps, Manifolds, etc.
(Outdoors)
[See Rules 19-102(2)(c), (3)(a)]

Grade Level
Additional when heavier-than-air vapours are present
Diagram B13 – Transmission or Process Facility
[See Rules 19-102(2)(a), (b), (c) & (e), and (3)(b), (d) & (f)]

Hazardous Area Classification

Zone 0  Zone 1  Zone 2

Diagram B14 – Storage tank for Flammable Liquid
[See Rules 19-102(1)(a) & (b), (2)(c) & (e), (3)(c) & (f)]
Diagram B15 – Water Flood Disposal

[See Rules 19-102(1)(a) & (b), (2)(c) & (e), (3)(c) & (f), and 19-108]

Hazardous Area Classification

Zone 0  Zone 1  Zone 2

Gas Storage or Surge Tanks

Zone 0 for 0.5m around vent
Zone 1 between 0.5m & 1.5m
Zone 2 between 1.5m & 3m

Note: This diagram is specific to water flood disposal systems. It should not be used as a guide for assuming that a Zone 2 classification does not extend beyond the building or enclosure for other types of facilities that are classified Zone 2.

Diagram B16 – Process Vents and Instrument & Control Device Vents

[See Rules 19-102(1)(c) & (d), (2)(f) & (g), (3)(g) & (h)]

Zone 0 for 0.15m around vent
Zone 1 between 0.15m & 0.5m
Zone 2 between 0.5m & 1m

Gas Operated control devices

Process Equipment Vent

[See Appendix B note 19-102 (1)c), (2)(f) & (3)(g)]
Appendix C19

THE COMMITTEE ON THE CODE FOR ELECTRICAL INSTALLATIONS AT OIL AND GAS FACILITIES

Organization and Rules of Procedure

1. General

1.1 The Committee on the Code for Electrical Installations at Oil and Gas Facilities (hereinafter referred to as the O&G Code Committee) is an advisory committee to SaskPower Electrical Inspections.

1.2 The Committee shall be responsible for advising on changes to the Code for Electrical Installations at Oil and Gas Facilities (hereinafter called the O&G Code), which shall consist of safety standards for electrical installations used in the search, transmission, or production of oil, natural gas and related hydrocarbons.

2. O&G Code Committee

2.1 Terms of Reference. The Committee on the O&G Code shall be responsible for:

(1) Recommending amendments to the O&G Code;
(2) Recommending interpretations to the O&G Code;
(3) All policy matters related to O&G Code Committee development work;
(4) Setting up procedures that will facilitate feedback from industry, users, and others to the Committee on the O&G Code; and
(5) Establishing and maintaining liaison with SaskPower and other national and international organizations concerned with safety standards for electrical installations used in the search, transmission, or production of oil, natural gas and related hydrocarbons.

2.2 Members

2.2.1 The Chair of the O&G Committee shall appoint the Committee members. Requests for membership shall be directed through the O&G Code Coordinator, who shall coordinate such requests with the Committee Chair.

2.2.2 The O&G Code Committee is composed of members selected from the oil and gas industry representing the viewpoints of:

(1) Multiple provincial electrical authorities having jurisdiction
(2) Corporations
(3) Drilling Contractors
(4) Electrical Contractors
(5) Designers/Engineers
(6) SaskPower
(7) Others as determined by the Oil and Gas Committee
2.2.3 It is further recommended that:
(1) The O&G Code Committee be composed of not more than 10 members;
(2) At the discretion of the Committee Chair, the number of members be increased if further representation is required;
(3) Not more than one-third of the membership be from any one category;

2.2.4 Members nominated are by the interest or organization they represent and their appointment shall be subject to the approval of the Chair of the O&G Code Committee.

2.2.5 Members shall participate actively in the work of the O&G Code Committee.

2.2.6 The Chair of the O&G Code Committee, after consultation with the nominating interest and the O&G Code Committee, may direct removal of a member who:
(1) Fails to respond promptly and appropriately to Committee correspondence; or
(2) Fails to be actively and appropriately involved in the work and responsibilities of the Committee.

2.2.7 The O&G Code Committee should consult with individuals or organizations outside the membership of the O&G Code Committee when specific data or information may be required. Experts on specific subjects may be asked to attend meetings of the Committee, or to submit special data or information to the Committee for its use.

2.2.8 The O&G Code Committee Chair may set up Task Groups to study and report on specific problems. Task Groups may include individuals having expertise not available within the Committee.

2.2.9 Members of the O&G Code Committee shall be provided with the names and addresses of the other members of the Committee.

2.2.10 The O&G Code Committee Chair should review periodically the performance of each member of the Committee, and decide on any changes to the Committee membership. Consideration should be given to the calibre of responses to correspondence, promptness in responding to requests for comment, and attendance at meetings.

2.2.11 Members of the O&G Code Committee should review, on a continuing basis, the O&G Code for which they are responsible, and initiate proposed amendments where considered desirable.

2.3 O&G Code Committee Operation

2.3.1 After receiving a proposal from the O&G Code Coordinator, the Chair shall review the proposal and shall submit it to the O&G Code Committee members.

2.3.3 Meetings shall be held as necessary.

2.3.4 Decisions at meetings or through correspondence shall be based on the consensus principle.

NOTE: As defined by the Standards Council of Canada in CAN-P-2E, consensus in standardization practice is achieved when substantial agreement is reached by concerned interests involved in the preparation of a standard. Consensus implies much more than the concept of a simple majority, but not necessarily unanimity.

2.3.5 The O&G Committee Chair shall report the recommendation of the Committee on the proposal to the O&G Code Coordinator.

2.3.6 O&G Code Committee reports should make use of the standard format (see Annex A).
and should include, in addition to the proposal, the name of the submitter and the affiliation, the reason for the proposal, a summary of the Committee's deliberations, and the Committee's recommendation.

2.3.7 The Committee's deliberations should include the comments of any members who may not be in agreement with the recommendation.

3. Requests for Amendments to the O&G Code - General

3.1 A request for an amendment to the O&G Code, may be submitted to the O&G Code Coordinator by any person, organization, or committee (see Annex B).

3.2 A request for an amendment to the Code shall include a specifically worded proposal together with reasons for the proposal and supporting data. The wording to be added, changed, or deleted shall be submitted in such a way that the intent is clear. An unclear proposal may be returned to the submitter by the O&G Code Coordinator after consultation with the O&G Committee Chair.

3.3 The O&G Code Coordinator shall assign a subject number and shall submit the request to the Chair O&G Code Committee for the preparation of a report and recommendation by the Committee (see Clause 2.4).

4. Code Format and Rule Terminology

4.1 The O&G Code shall follow the “Code Format and Rule Terminology” requirements of Appendix C, Clause 12 in the Canadian Electrical Code, Part I.
(Third Edition 2006)
Annex A
Code for Electrical Installations at Oil and Gas Facilities
Committee Report

Subject No.: 

Chair: 

Title: 

Date: 

Submitted by: 

Date: 

Affiliation: 

Request or Proposal: 

Reason for Request or Proposal: 

Supporting Information: 

Summary of O&G Code Committee Deliberations: 

O&G Code Committee Recommendation:
Annex B

TO: The Code Coordinator for the Code for Electrical Installations at Oil and Gas Facilities

FROM:

AFFILIATION:

DATE:

RE: Request for an amendment to Rule(s)

Request (Specifically Worded):

Reason for Request:

Supporting Information:

For office use only:

Subject No. Assigned:

Completed form to be sent to: O&G Code Committee Chair
Submitter
Appendix D19

Engineering Guidelines for Determining Area Classifications

This guideline section is not intended as a mandatory code for developing area classifications.

**Rule 19-100 (1)**

The intent of this guideline is to promote awareness of the various industry codes, standards, and recommended practices, which are available and can be used when performing area classification studies. These references provide extensive information for many types of facility situations, which are commonly encountered in the Canadian oil and gas industry; however, knowledge and experience concerning the application of these codes, standards, and recommended practices is also needed in order to properly apply them for a given situation. This guideline intends to identify, at a high level, the most common considerations, which need to be addressed when performing an area classification.

2. **Stakeholders:**

This guideline is focused on engineering and design requirements essential for proper area classification, but also identifies requirements, which affect other stakeholders such as original equipment manufacturers, installers, inspectors, operations, safety, and maintenance personnel. Aside from these obvious stakeholders, there are other stakeholders who may be impacted by the area classification or require access to the documents – such as insurers or regulatory representatives (worker safety or code enforcement).

3. **Scope:**

Per the general scope of the Code for Electrical Installations at Oil and Gas Facilities rule 19-000, the scope of this guideline focuses on facilities used in the search, transmission, and production of crude oil, natural gas, and related hydrocarbons.

More complex facilities or processing situations (such as petrochemical plants and refineries), where more complex fluid behaviour, larger volumes or flow rates, higher pressures, more complicated facility configurations, or more complicated operations, are present, are not considered in this guideline.

Area classification codes, standards, and recommended practices do not address catastrophic release situations (see API RP505 1.2.1(b)). Other procedures and response plans should be put in place by facility operators to address these possibilities.
4. Requirement for Multi-Disciplinary Involvement:

Electrical designs and installations in hazardous locations depend upon the area classifications for a facility. However, defining an area classification is dependent upon various factors including, but not limited to:

- characteristics of the fluids being handled (chemical and physical properties such as flash point, molar composition, liquid density, vapour specific gravity, lower explosive limit, upper explosive limit, mole weight, etc.)
- operating pressures, temperatures, flow rates, and volumes
- design and maintenance of the compression, pumping, piping, valve, and containment systems handling the fluids
- building design and dimensions
- heating and ventilation systems for buildings
- site layout and location near other structures
- existence and type of safety systems such as gas detection
- operating and maintenance practices and training
- operating, maintenance, and failure histories and experience
- outdoor terrain and topographical features (e.g. berms, low spots, slopes, vegetation)
- local temperature and wind conditions
- remoteness of an installation, or ability to detect and/or respond to a release through onsite personnel or remote monitoring
- facility changes resulting from site operations or maintenance which may impact the area classification boundaries

Many of the above factors are best understood by disciplines other than electrical engineers and designers. These disciplines may include:

- process engineers
- heating and ventilation engineers
- air quality scientists or engineers
- operations specialists
- fire and safety specialists
- maintenance personnel
- instrumentation engineers

Hence, an area classification may require input from some or all of these respective disciplines. It should be decided by corporate policies and/or engineering staff, based on the scope and complexity of the project, if and when these various skill sets need to be used, and what their level of involvement needs to be. The individual leading the area classification study should be knowledgeable and competent in the principles of area classification.
5. **Responsibility for Training and Competence:**

The engineering profession is responsible for determining what levels of competence are required for a given discipline or activity. There is currently no regulated “certification” requirement verifying competence for an engineer in order to perform an area classification study. However, there is still professional responsibility for the practicing engineer to be knowledgeable and competent in practicing the profession, hence in performing an area classification study.

In order to become competent in performing an area classification study, various approaches are encouraged:

- taking industry sponsored training on area classification techniques
- participation in codes and standards development bodies
- mentorship by more experienced engineers
- reading and understanding the various codes and standards
- on-the-job performance of area classification studies (with appropriate supervision), starting with simple situations and moving towards more complex situations
- reviewing existing area classification studies
- reviewing incidents and failure histories, and participating in investigations and corrective or remedial projects
- developing and delivering area classification training programs

6. **Requirement for Engineering Authentication:**

Where an engineer is involved, all area classification drawings and studies should be traceable to a registered professional engineer working under a permit to practice. Traceability and authentication requirements are governed by the respective jurisdiction, but typically this means that drawings and reports are signed and stamped, or signed with the title P. Eng. (or equivalent).

7. **Engineering Quality Controls:**

In addition to competency and training of the individual professional engineer, the engineering project structure should also include peer or supervisory reviews of area classification documents.

8. **Documentation and Records:**

Area classification drawings and their supporting studies should be maintained on file with the owner/operator of the facility for the life of the facility plus any additional legally required time period thereafter. The professional engineer and/or engineering company that prepared the reports and drawings should
also maintain those records per any regulatory and/or contractually required time periods. These records should be accessible, upon request, by any affected stakeholder.

In order to avoid long searches for old project files, all relevant information should be recorded on the area classification drawing itself, e.g. results of fugitive emission studies with date or revision number, minimum ventilation rates, rationales, process conditions, and any other important comments. See also Section 11 “Drawing Requirements” below.

Note that company specific operating and safety procedures may require onsite access to, or posting of, area classification drawings for convenient reference. If this is the case, drawings should be well organized, uncluttered, and easy to understand.

9. Management of Change:

Area classification studies and drawings are based on certain assumptions and conditions. If process or operating conditions change (due to plant expansions, equipment relocations, changes in inlet or process streams, changes in operating pressures, changes in operating procedures, alteration of building ventilation, changes in site grading, etc), or if conditions are not adhered to (e.g. gas detection is no longer maintained in proper working order), then the area classification may be rendered invalid. Depending upon the exact nature of the changes, this may lead to an unsafe condition. Actions should be taken to ensure that a valid area classification is put in place and its requirements are adhered to.

A management of change process should be in place to ensure that an area classification is valid and being followed at all times throughout the life of a facility. This may require changes to designs and installations, changes to procedures, changes to the area classification studies, revisions to drawings, etc. All documentation sets should be updated, and all affected stakeholders should be notified of the changes and potential impacts.

As part of a management of change process, appropriate engineering review and sign-off should be included. Engineering accountability is present not only for initial project design, but also throughout the life of a facility.

10. Communication Responsibilities:

As mentioned above, when area classification studies are completed and drawings are made, there are various conditions and assumptions the study contains, which must be valid in order to make the study valid. At the outset of a project, the classifying engineer should communicate these requirements to the various project, construction, inspection, operating, and maintenance...
stakeholders who will be responsible for ensuring that these conditions are satisfied during the initial installation and throughout the life of the facility. This may involve various communication or design approaches including:

- including area classification studies in project data books
- including appropriate notes on drawings
- holding training sessions
- specifying various warning signs in and around the classified areas
- specifying posting of area classification drawings and/or studies which have important details
- specifying building interior classification signs
- specifying fencing or barriers to restrict access
- specifying other equipment which helps to ensure conformance (e.g. travel stops on louvers)

11. Drawing Requirements:

Area classification drawing sets typically consist of combinations of site plans, elevation or sectional views, details, and clarifying notes. These show the indoor and outdoor zone classifications in and around buildings using standard cross-hatching markings. Typically there will be several installation details for specific equipment configurations and situations requiring finer detail (e.g. process or instrumentation vents or pig traps), which may be similar to the diagrams presented in the Code for Electrical Installations at Oil and Gas Facilities. Drawings should include the following types of basic information:

- area classification information (including classes, zones, grouping and maximum allowable surface operating temperatures for electrical equipment)
- legends for diagrams explaining various hatchings (following IEC recommendations)
- diagrams showing the extent of the various zones
- assumptions, notes, and conditions
- site locations, professional engineering stamps, and other title block information
- bar scales embedded in the drawing which automatically scale with the drawing as it is printed out on different paper sizes

Engineered drawings may be custom to a site, or typical, depending upon the complexity of the situation:

- Facilities will typically have a site specific engineering drawing set due to the complexity of the site.
- Simple installations, such as stand-alone pumpjacks or wellheads, may use typical drawings as outlined in company standards without providing drawings for each individual small facility. These typicals
should only be used when they accurately represent the installation.

When references are made on the drawings to key area classification supporting information, assumptions, and conditions, this should be done in such a manner so as to avoid too much congestion on the drawing. For example, basic information could be put on the drawings along with a reference to more detailed documentation or a study.

Examples of key supporting information, assumptions, and conditions may include (as appropriate):

- references to file numbers, dates, and author’s names for supporting area classification studies
- reference to documentation on composition and physical property parameters of the process fluids (e.g. mole weight, relative density, lower explosive limit, upper explosive limit, autoignition temperatures, volume or molar compositions, etc.);
- operating conditions (pressures, flow rates, or volumes); these may be specific “point” values, or may be ranges if the area classification was performed for a range of conditions
- calculation methods (e.g. API RP505 Appendix B) with supporting data and assumptions
- hydrocarbon leakage rates (plus references used)
- fresh air introduction rates
- safety factors assumed
- internal and external ambient temperatures (point or range values)
- minimum natural or forced ventilation rates
- louver sizing and/or travel stop settings
- text and layout for warning signs or labels
- combustible gas detection requirements (sensors, locations, alarm and shutdown actions); some of this information may be communicated in shutdown keys or other documents
- vapour tight sealing requirements for walls or other barriers
- purging and/or pressurization requirements
- a warning to review and update studies and drawings when conditions deviate from those specified

12. Inspection Requirements:

Field and shop inspectors should be provided with the engineered area classification drawings and studies applicable to the facility to be inspected. In the absence of this information, the requirements of the Code for Electrical Installations at Oil and Gas Facilities shall apply. However, the absence of engineered area classification drawings and studies may lead to an unsafe situation if the appropriate engineered area classification would have otherwise required zone ratings or distances that exceed the requirements of the Code for
Electrical Installations at Oil and Gas Facilities. This is why, the inspector should be furnished with the current engineered area classification.

13. Information Sources and References:

When preparing an area classification, there are numerous information sources and references that can be used. Explained below are some of the most commonly used sources, and typical information which may be obtained from them:

- Canadian Electrical Code CSA C22.1 Part 1. In particular Section 18, and Appendices B, F, H, and J provide the formal definitions for area classification, requirements for wiring methods, and requirements for equipment.
- Code for Electrical Installations at Oil and Gas Facilities. Use this code when the area classification has not been done by a professional engineer. This code sets minimum requirements for typical oil and gas production facilities.
- Alberta STANDATA (Electrical). Provides interpretations and clarifications on various area classification related subjects. Other provinces may have equivalent advisory systems.
- API RP505 Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I Zone 0, Zone 1, and Zone 2 (API RP500 is the companion document for the North American division system). Contains numerous examples of typical area classifications for oil and gas facilities (based on experience). Also contains a “fugitive emissions study” calculation method in Appendix B and a “point source” approach in Appendix D. Appendix E contains a classification procedure that provides simple questions to guide how classifications are to be performed.
- API 4615 Emissions Factors for Oil and Gas Operations. Provides field measured and statistically classified emissions factors.
- API 4638 Calculations Workbook for Oil and Gas Production Equipment Fugitive Emissions. Contains several worked fugitive emissions calculations.
- NFPA 497 Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas. Oriented towards chemical facilities, however, it does contain an extensive list of flammable and combustible materials and their physical properties which is useful in performing area classification studies.
- IEC 60079-10 Electrical Apparatus for Explosive Gas Atmospheres – Part 10: Classification of Hazardous Areas. Provides definitions of many area classification terms that are used in other codes. Provides an area classification method/process that factors in the grade of the release and ventilation. Provides calculation examples, sample area
classification diagrams, and a data collection table. Provides a means of estimating “hypothetical volumes” for quick checks of emission propagation distances.

- ISA RP 12.24.01 Recommended Practice for Classification of Locations for Electrical Installations Classified as Zone 0, Zone 1, or Zone 2. ISA’s adaptation of IEC 60079-10. Incorporates the use of gas detection as a means of classifying indoor areas Class I Zone 2.

- IP 15 Model Code for Safe Practice Part 15 Area Classification Code for Installations Handling Flammable Fluids. Provides information on the point source concept and how to use it. Contains several direct examples for both onshore and offshore installations. Supporting documents to this one provide detailed calculation information and risk assessment methodologies.


- IEC60079-20 Electrical Apparatus for Explosive Gas Atmospheres – Part 20: Data for Flammable Gases and vapours, relating to the use of electrical apparatus. Provides a complete set of material properties; intended for area classification purposes.

- Occupational Health and Safety Codes. Various provinces contain specific safety requirements that may reference area classifications. This may have impacts upon the design, operations, or maintenance of installations in hazardous location.

- Canadian national product standards for equipment certification (e.g. CSA Part II standards). Provides technical information on how products are certified for hazardous locations using various protection methods. Also provides marking information.

- Corporate drawing details, standards, guidelines, and best practices. May contain various specific approaches, requirements, and details as used by a specific corporation. Must meet minimum regulatory requirements.

- Vendor and manufacturer sources. Manufacturers provide guides and lookup/reference information useful in educating, classifying, designing, installing, and maintaining.

- Technical Papers. IEEE PCIC, ISA, and other organizations produce many papers annually, which address numerous area classification issues.

- Reference Texts. Several excellent educational and information sources are available from experienced authors, some examples are listed below:
  - Electrical Instruments in Hazardous Locations; Magison, Ernest.
Annex J19 - Oil and Gas Facilities

Scope

J19-000 Scope (see Annex JB19)
(1) This Annex applies to electrical installations used in the search, transmission, or production of oil, natural gas and related hydrocarbons.
(2) This Annex does not apply to electrical installations used in:
   (a) petroleum refineries;
   (b) petrochemical facilities;
   (c) gas distribution systems operated by a gas utility at a pressure of 700 kPa or less for the purpose of distributing gas to consumers in all or part of a municipality; and
   (d) fuel supply systems for equipment.
(3) This Annex is supplementary to, or amendatory of, the requirements of the CEC.

J19-002 Interpretation
This Code and any standards referenced herein do not make or imply any assurance or guarantee by the authority adopting this Code with respect to life expectancy, durability or operating performance of equipment and materials referenced herein.

General

J19-050 Grounding
A ground detection device is not required for the ungrounded secondary circuit of a supply transformer for a single downhole submersible oil pump.

J19-052 Installation of Electrical Equipment (see Annex JB19)
(1) Flexible cord or portable power cable shall be permitted at drilling and servicing sites or oil and gas wells provided the flexible cord or portable power cable:
   (a) is suitable for exposure to oil and wet locations;
   (b) is supported, protected or located in a manner that prevents mechanical damage; and
   (c) otherwise complies with the requirements of CEC rules J18-120(a),(b),(c) and J18-172(a),(b),(c) for Class I locations.
(2) A lockable switch in the control circuit of the motor contactor for DC traction motors on drilling and servicing rigs may be used for the disconnecting means required by Section 28 of the CEC where the switch is located at the motor contactor.
(3) Lighting fixtures and portable equipment shall be supported independently of the cord and protected from mechanical injury by guards or equivalent means.
(4) A combination motor controller shall be permitted to be used as service equipment for a single oil well pump.
Classification of Oil and Gas Facilities

J19-100 Hazardous Area Classification (See Annex JB19 and Appendix D19)

(1) Classification of hazardous locations established and documented by a professional engineer under the engineer’s seal and signature shall be the area classification.

(2) Where a facility has not been classified in accordance with Subrule (1), or evidence of an engineer’s involvement is not satisfactory to the inspection authority having jurisdiction, Rules J19-102 to J19-108 shall be the minimum requirement.

J19-102 Common Classifications for Oil and Gas Facilities (See Annex JB19)

(1) The following are Class I, Division 1 hazardous locations:

(a) the interior of buildings or enclosures housing tanks, pumps, valves, flanges or other equipment that is a potential source of leakage of flammable liquid, gas, or vapour, except that shed type enclosures shall be permitted to be Class I Division 2 hazardous locations when open on 3 sides from grade to roof level and roof ventilators are provided where lighter-than-air gases may accumulate;

(b) the interior of buildings or enclosures, any part of which is located in a Class I, Division 1 hazardous location, unless the buildings or enclosures are separated from the classified area by a vapour-tight barrier;

(c) any pit, depression or area below grade in a Class I, Division 2 hazardous location where flammable liquids or flammable heavier-than-air gases and vapours may accumulate;

(d) the area within 1.5 m of a tool launcher/receiver opening or other similar facility;

(e) the area within 1.5 m around an atmospheric vents when venting from a Division 1 area;

(f) a minimum area within 1.5 m around an equipment process vent;

(g) the area within 0.5 m around an instrument or control device vent; and

(h) the vapour space inside enclosed vessels or tanks containing a substance capable of producing an explosive gas atmosphere.

(2) The following are Class I, Division 2 hazardous locations:

(a) outdoor or unenclosed areas within 3 m in any direction of a potential source of leakage of flammable liquid, gas or vapour;

(b) outdoor areas within 3 m of the outer confines of buildings or enclosures that are Class I, Division 1 hazardous locations, plus an additional horizontal distance of 4.5 m to a height of 600 mm above grade level where flammable liquids or flammable heavier-than-air gases and vapours may accumulate, unless the outer confines of the building are vapour-tight;

(c) the area within 3 m in any direction of any flammable gas or liquid storage vessel or tank and, where flammable liquids or flammable heavier-than-air gases and vapours may accumulate:

(i) an additional horizontal distance of 4.5 m to a height of 600 mm above grade level, or

(ii) when a dike is provided, the area within the perimeter and extending up to the top of the dike;
(d) the interior of buildings or enclosures, any part of which is located in a Class I,
Division 2 hazardous location, unless the buildings or enclosures are separated
from the classified area by a vapour-tight barrier;
(e) the area between 1.5 m and 3 m of a tool launcher/receiver opening or other
similar facility;
(f) the area around atmospheric vents:
   (i) for 3 m when venting from a Division 2 area; or
   (ii) between 1.5 m and 3 m when venting from a Division 1 area;
(g) a minimum area of between 1.5 m and 3 m around an equipment process vent;
and
(h) the area between 0.5 m and 1 m around an instrument or control device vent.

J19-104 Supplemental Classifications for Oil and Gas Drilling and Servicing Operations
(See Annex JB19)
The Following are Class I, Division 2 hazardous locations:
(a) the interior of buildings or enclosures housing tanks for normal well kill or
circulating fluids where the fluids do not normally contain substances capable of
creating an explosive gas atmosphere;
(b) the interior of buildings or enclosures housing open mixing or solids control
apparatus;
(c) areas within 2 m of mud tanks and shale shakers where an enclosure is not
provided;
(d) the entire area above the rig floor to the top of the enclosure, if provided, or to a
height of 3 m, whichever is greater;
(e) the entire area under the rig floor or the area below the rig floor within 2 m
horizontally of the centre of the well where the substructure is of the open type;
(f) the area within 2 m horizontally of the centre of the well and 3 m vertically of the
uppermost well bore opening where a rig floor is not provided; and
(g) the area within the choke manifold building.

J19-106 Supplemental Classifications for Oil and Gas Wells (see Annex JB19)
(1) The area within 1.5 m in any direction of a casing vent where explosive gas
atmospheres are present under normal operation is a Class I, Division 1 hazardous location.
(2) The following are Class I, Division 2 hazardous locations:
(a) the area within 1.5 m in any direction of a casing vent where explosive gas
atmospheres are not present under normal operation;
(b) the area between 1.5 m and 3 m in any direction of a casing vent where explosive
gas atmospheres are present under normal operation; and
(c) the area within 1.5 m horizontally of a junction box used for connection to a
submersible pump downhole cable and extending from 1.5 m above the box to
grade level, unless a wellhead feed-through-device is installed that prevents the
migration of explosive gas atmospheres through the cable.
J19-108 Supplemental Classifications for Water Flood and Disposal Systems
(See Annex JB19)

The following are Class I, Division 2 hazardous locations:

(a) the interior of buildings or enclosures housing produced water injection wells; and

(b) the interior of buildings in which water produced in conjunction with crude oil or fresh water containing gas is stored or processed or is subject to pumping operations.
Annex JB19
Notes on Rules for Annex J19

The notes and diagrams in this Annex are for information and clarification purposes only and apply to the following rules:

Rule | Note
--- | ---
J19-000 | **Persons using this Code should be aware of other regulatory requirements such as in the areas of energy, occupational health & safety and environment.**

See also Appendix J and notes on rules 18-000, 18-002 and 18-006 in Appendix B of the CEC.

Where installations are not covered by this Code [J19-000(2) (a) to (d)], sound engineering principles should be applied to determine if an installation should be classified in accordance with Rules 18-004 and 18-006 of the CEC.

J19-052 | **This rule allows for additional situations not specifically addressed in the CEC.**

Users should give careful consideration to electrical installations where adverse conditions expose electrical equipment to a corrosive environment or to excessive moisture. The nature of activity at oil well servicing or drilling operations (i.e., equipment subject to splashing or direct streams of water), may require the use of “Type 4” enclosures, “type TE” motors or equivalent. For additional information on IEC Ingress Protection (I.P.) designations, refer to IEC Standard 529 and CEC Appendix B note to rule 18-106(5).

J19-052(1) | **The use of flexible cord at drilling and servicing sites or oil and gas wells is intended to recognize situations where fixed wiring methods cannot provide the necessary degree of movement for fixed or mobile electrical equipment required to be frequently moved. It is not intended to be a substitute for fixed wiring. Excessive length, quantities and use of flexible cord or portable power cable is to be avoided.**

J19-052(4) | **The use of a combination motor controller as service equipment for a single oil well pump may be appropriate where the utility has no meter or where the supply service requirements of the CEC permit “hot” metering installations. The supply authority should be consulted for metering requirements.**

When a small auxiliary load must also be supplied, a single feeder may be ‘tapped off’ the combination motor controller in compliance with Rules 12-3032(2) & 14-100 of the CEC. When adding an auxiliary load, consideration should be given to the main overcurrent device and the feeder or service conductors of the combination motor controller to ensure they are properly sized.
This rule recognizes the expertise of an engineer in classifying Oil and Gas facilities. The engineer must be experienced in determining area classifications for hazardous locations as outlined in Rule 18-006 of the CEC and knowledgeable in using industry-recognized standards and recommended practices. (See notes on rule 18-006 in Appendix B of the CEC.) Without engineering involvement, the requirements for classifying hazardous locations in rules 19-102 to 19-108 are the minimum requirements. When applying these minimum requirements, users are advised of their responsibility to ensure that they are adequate for the installation. Circumstances may dictate the need to exceed these rules to achieve an acceptable level of safety performance.

Rule 19-102 outlines area classifications for various installations that can be common to all types of oil and gas facilities. Rule 19-104 to 19-108 outline additional or supplemental area classifications for situations encountered at specific installations. The term “flammable” used throughout these rules with the words liquids, gases, and vapours should be taken in the context of the likelihood for these substances to create an explosive gas atmosphere. For more information on flammable liquids, gases and vapours see American Petroleum Institute RP500 & RP505 and NFPA Standard No. 30. To aid in the application of these rules, see the Diagrams JB1 to JB16.

To differentiate between different types of vents, the term is divided into three distinct categories: process equipment vents (e.g., pressure relief valves, blow-downs, etc.), instrument and control device vents (e.g., vents from gas actuated control devices, gas chromatograph vents, etc.) and atmospheric vents (e.g., building ridge vents, roof vents, tank vents, etc.). See American Petroleum Institute RP500 & RP505 for further information.

When we interpret the requirement of roof ventilators for shed type buildings or enclosures, we should take into consideration the shape of the roof. In contrast to a gabled roof, flat roofs would not normally allow a significant accumulation of lighter than-air-gases unless the fascia or roof edge prevented those gases from dispersing.

Classification requirements for process equipment vents are expressed in terms of absolute minimums. Criteria affecting classification of areas around process equipment vents in non-enclosed areas are diverse. Sound engineering judgement should be applied for specific cases, but in no case should the classification be less than those in the referenced rules and those shown in Diagram JB16.
When locating enclosures or buildings (with electrical equipment intended for non-hazardous locations) adjacent to a classified area, we should consider the boundary of the classified area as being an arbitrary line. Even though the building or enclosure does not infringe upon the classified area, care should be taken to avoid locating them in close proximity to these areas, unless they have a vapour-tight barrier. American Petroleum Institute RP500 and RP505 define vapour-tight barrier as a barrier that will not allow the passage of significant quantities of gas or vapour at atmospheric pressure.

△ A risk analysis by the Canadian Association of Oilwell Drilling Contractors has determined that the probability of an explosive gas atmosphere occurring in a “doghouse” located outside the hazardous area of a drilling rig floor (with or without winter enclosures) is less than 1 hour in 100 years. The 1 hour in 100 years probability or less is the industry accepted norm for determining non-hazardous locations. For this reason, the “doghouse” located outside the hazardous area of the floor of a drilling rig is unclassified. Owners/operators may adopt policies that impose a more stringent wiring method as well as limit the type of equipment that can be used in the “doghouse”.

△ J19-108 The water flood / water disposal situation as described by Rule J19-108 and shown in Diagram JB15 assumes that water in the course of its use has been contaminated with flammable liquids or vapours but has gone through multiple stages of separation or filtration and is virtually non-flammable. However enclosures housing such water flood / disposal equipment are classified Division 2 in the event that the filtration or separation process fails. Because the expected release rate from the water flood/disposal building is insignificant, the classification outside the water flood/disposal building is omitted in Diagram JB15.

Rule J19-108 can also assume situations where the water is likely to contain flammables due to process upset conditions but the associated equipment in the enclosure is vented to the outside of the enclosure. If equipment vents are not extended to the outside of the enclosed area, the enclosure should be classified Division 1.

Rule J19-108 is not intended for situations where produced/processed water is likely to contain flammables on routine occasions or that could release sizeable quantities of flammables for extended periods. These types of situations call for proper engineering in accordance with Rule J19-100(1) or could alternatively be classified as a process facility in accordance with Rule J19-102.
Annex JB19 Diagrams

Diagram JB1 – Service Rig
(Sub-structure and rig floor are not enclosed)
[See Rules J19-104(d) & (e)]

Hazardous Area Classification

- Division 1
- Division 2

Grade Level

Rig Floor

3 m

2 m
Diagram JB2 – Drilling Rig

[See Rule J19-104]

Hazardous Area Classification

Division 1  Division 2

Plan View
Diagram JB3 – Mud Tank in a Non-enclosed Area
(Normal well kill or circulating fluids)
[See Rules J19-104(c)]

Hazardous Area Classification

Division 1
Division 2

Diagram JB4 – Mud Tank in a Enclosure
(Normal well kill or circulating fluids)
[See Rule J19-104(a)]
Diagram JB5 – Mud Tank in an Enclosure
(Explosive gas atmospheres are present)
[See Rules J19-102(1)(a), (2)(b)]

Diagram JB6 – Solids Control Apparatus in an Enclosure
(Mud-mix, De-sander, De-silter, etc.)
(Explosive gas atmospheres are not normally present)
[See Rule J19-104(b)]
Diagram JB7 – Wellhead in an Enclosure
[See Rules J19-102(1)(a), (2)(b)]

Hazardous Area Classification

Division 1
Division 2

Diagram JB8 – Junction Box for Submersible Pumps
(Adequately ventilated area)
[See Rules J19-106(2)(b)]
Diagram JB9 – Enclosed Area Adjacent to a Classified Area
[See Rules J19-102(1)(b) & (2)(d)]

Hazardous Area Classification

Division 1

Division 2

Source

Area classified due to source outside enclosed area

Enclosed Area

Vapour Tight Barriers

Diagram JB10 – Tool Launching or Receiving Installation
(Adequately ventilated)
[See Rules J19-102(1)(d) & (2)(e)]
Diagram JB11 – Typical Wellhead
[See Rules J19-102(1)(c), (3)(a) and 19-106(1), (2)(a) & (b)]

Hazardous Area Classification

- Division 1
- Division 2

This area may be classified Division 1 or Division 2
[see J19-106 (1) & (2)(a & b)]

Diagram JB12 – Valves, Pumps, Manifolds, etc.
(Outdoors)
[See Rules J19-102(1)(c), (2)(a)]

Grade Level

Additional when heavier-than-air vapours are present
Diagram JB13 – Transmission or Process Facility
[See Rules J19-102(1)(a), (b), (c) & (e), and (2)(b), (d) & (f)]

Hazardous Area Classification
- Division 1
- Division 2

Diagram JB14 – Storage tank for Flammable Liquid
[See Rules J19-102(1)(c),(e) & (h) and (2)(c) & (f)]
Diagram JB15 – Water Flood Disposal
[See Rules J19-102(1)(c),(e) & (h), J19-102(2)(c) & (f), and J19-108]

Hazardous Area Classification
- Division 1
- Division 2

Note: This diagram is specific to water flood disposal systems. It should not be used as a guide for assuming that a Division 2 classification does not extend beyond the building or enclosure for other types of facilities that are classified Division 2.

Diagram JB16 – Process Vents and Instrument & Control Device Vents
[See Rules J19-102(1)(f) & (g) and (2)(g) & (h)]