TR Number	22-67
Primary	192.927
Purpose	Review and develop GM as appropriate in light of Amendment 192-132
Origin/Rationale	Amendment 192-132.
Notes	ICDA
Assigned to	IMCORR

Note: *Revisions are shown in yellow highlight and red font.*

Section 192.907

...

3 INCORPORATION BY REFERENCE

3.1 General.

(a) Subpart O requires use of documents that are incorporated by reference (IBR) in §192.7. An operator must meet the requirements of Subpart O and the referenced sections of those documents. In the event of a conflict between ASME B31.8S and NACE SP0502, the more stringent requirement should be followed.

(b) When developing a written program, an operator needs to consider applicable portions of the following documents that are IBR in §192.7 for Subpart O.

(1) ASME B31.8S and ASME B31.8, which ~~is~~ are IBR for this section.

(2) Other IBR documents used to develop the elements of an IMP (§192.911):

(i) ~~NACE SP0502~~ AGA, Pipeline Research Committee Project, PR–3–805.

(ii) ASME/ANSI B31G.

(iii) ~~GRI 02/0057~~ NACE SP0204.

(iv) ~~AGA, Pipeline Research Committee Project, PR–3–805~~ NACE SP0206.

(v) NACE SP0502.

3.2 ASME B31.8S.

...

(d) References in Subpart O to ASME B31.8S are listed below in Table 192.907i.

SUMMARY OF INCORPORATED REFERENCES TO ASME B31.8S	
ASME B31.8S	**Subpart O References**
General	§§192.907(b); 192.911; 192.913(a), (b)(1), & (c); 192.935(b)(1)(iv)
...	...
Section 5	§§192.917(c) & (d); 192.921(a)(2); ~~192.935(a);~~ 192.937(c)(2); 192.939(a)(1)(ii) & (a)(3)
~~Para 6.2~~	~~§§192.921(a)(1); 192.937(c)(1)~~
Para 6.4	§§192.923(b)(1) ~~& (b)(2)~~; 192.925(b), (b)(1), (b)(2), (b)(3), & (b)(4)~~; 192.927(b)~~
Section 7	§192.933(c), ~~&~~ (d)(1), & (b)(2)(iv)
...	...
~~Section 10~~	~~§192.911(m)~~

Section 11	§192.13(d) as referenced by §192.911(k)
Section 12	§192.911(l)
Appendix A	§~~§192.917(b);~~ 192.945(a)
~~Appendix A2~~	~~§192.927(c)(1)(i)~~
~~Appendix A3~~	~~§§192.923(b)(3); 192.929(b)(1) & (b)(2)~~
~~Appendix A3.3~~	~~§192.929(b)(1)~~
~~Appendix A3.4~~	~~§192.929(b)(2)~~
Appendices ~~A4.3 & A4.4~~ A-5.3 and A-5.4	§192.917(e)(4)
Appendix ~~A7~~ A-8	§192.917(e)(1)
~~Appendix B2~~	~~§§192.923(b)(2); 192.927(b)~~

TABLE 192.907i

Section 192.927

~~*This guide material is under review following Amendment 192-132*~~

Note: References to ~~ASME B31.8S~~ NACE SP0206 throughout this section of guide material are specific to the edition ~~of ASME B31.8S as~~ incorporated by reference (IBR) in §192.7. ~~See 3.2 of the guide material under §192.907.~~

1 PURPOSE

Internal Corrosion Direct Assessment (ICDA) is used to assess the integrity of the pipe that is subject to the threat of internal corrosion. ICDA is a process that identifies areas along the transmission pipeline where a liquid containing an electrolyte ~~may~~ might exist, and then focuses direct examination of the locations in covered segments where internal corrosion is most likely to exist.

2 GENERAL REQUIREMENTS

(a) A written ICDA plan should include its purpose, objectives, and instructions to personnel and must be based on the requirements of ~~the following~~ §192.927 and NACE SP0206.
~~(1) Section §192.927 and NACE SP0206 (see §192.7 for IBR).~~
~~(2) ASME B31.8S, Paragraph 6.4 and Appendix B2.~~
~~(3) GRI-02/0057 (see §192.7 for IBR), or its equivalent.~~

(b) For the purpose of this guide material, ICDA is applicable to transmission pipelines that normally carry dry gas (see §192.3) but ~~may~~ might have experienced infrequent introductions (upsets) of electrolytes into the system.

(c) A separate ICDA plan is required for a pipeline that carries electrolytes in the gas stream (i.e., wet gas). If ICDA is used as an integrity assessment under this condition, the operator is required to notify PHMSA and, if applicable, the state agency ~~180~~ at least 90 days before conducting the ICDA. See §§192.18, 192.927(b), and guide material under §§~~192.18,~~ 192.921~~,~~ and192.937. Operators may incorporate industry guidance such as NACE SP0110, "Wet Gas Internal Corrosion Direct Assessment" into their Wet Gas ICDA plans.

~~(d)~~ ~~Where a covered segment is present, the~~ An ~~ICDA region includes the portion of the pipeline from each location where an electrolyte~~ ~~may~~ might ~~first enter the pipeline~~ ~~upstream of any covered segment~~ ~~(input)~~ ~~to the farthest downstream point from the input where internal corrosion might have occurred (even if this point is downstream of the covered segment)~~ ~~until another input might introduce water or electrolyte and for which physical characteristics and~~

~~flow are similar. A significant change in water or flow characteristics or operating history of the segment might trigger a new ICDA region.~~

(~~d~~e) Other pipeline integrity threats, such as external corrosion or mechanical damage, ~~may~~ might be discovered in the direct examination phase of ICDA. When such threats are detected, alternative or additional methods for assessments may be required.

(~~e~~f) ICDA consists of four steps:

(1) Pre-assessment.

(2) ~~ICDA region identification~~ Indirect Inspection.

(3) ~~Identification of locations for excavation and direct~~ Detailed examination.

(4) Post-assessment evaluation and monitoring.

Note: This guide material reflects the steps as outlined in §192.927; specific tasks might be named or sequenced differently in ~~the IBR~~ NACE ~~document~~ SP0206.

~~(g) When conducting ICDA for the first time on a covered segment, an operator is required to apply more restrictive criteria that should be considered for each step of the ICDA process (see §192.927(c)(5)(ii)).~~

(~~h~~ f) In accordance with §192.947, each decision, analysis, and process developed to support each step is required to be documented.

3 PRE-ASSESSMENT

The objective of pre-assessment is to gather data for the determination of ICDA feasibility.

3.1 Data collection.

(a) This step involves collecting, reviewing, and integrating historical data for the pipeline segment. Data may be obtained from various sources including the following.

(1) Operating and maintenance records.

(2) Field visits.

(3) Alignment sheets.

(4) Risk assessment process.

(5) Input from subject matter experts.

(6) Other relevant information.

(b) To assist in data collection, an operator should prepare a facility description and collect related historical data on operations and inspections, including upsets and repairs. The data collected in the pre-assessment step often includes the same data typically considered during an overall pipeline threat assessment. The pre-assessment step may be conducted in conjunction with ECDA or other threat assessment efforts.

(c) In accordance with NACE SP0206, Section 3 ~~§192.927(c)(1) and ASME B31.8S, Appendix A2~~, the information in Table §192.927i is ~~required to be~~ collected, integrated, and assessed to determine the following.

(1) Whether ICDA is feasible.

(2) ICDA regions.

(3) W~~w~~here internal corrosion is likely to occur.

*[**Editorial Note:** The table below has been rewritten and replaces the existing table, which is also shown further below with strikeout.]*

Information for Dry Gas ICDA		
Category	**Data Types**	**Key Decision Points & Comments**
Diameter & wall thickness	Nominal pipe diameter	Diameter records might be contained in work order files, mapping system, or other historical files.
	Wall thickness	Wall thickness records might be contained in work order files or other historical files. Changes in wall thickness might affect ICDA regions.
Flow coatings (Internal coatings)	Internal coating location(s), if applicable	Internal coating makes it difficult to determine where corrosion might occur and might make ICDA unsuitable.

Elevation Profile	Topographical data including consideration of a pipeline depth of cover.	Known changes in depth of cover must be considered when determining the elevation profile. Due to deeper burial depths, examples of pipeline profiles of interest include: directional drilling and crossings of waterways, highways, railroads, pipelines, other utilities, culverts, and landfills.
Features with inclination	• Crossings • Valves • Drips, etc.	Drips, valves, dead legs, tapping fittings, low spots, and other features are locations where fluid might collect. Due to deeper burial depths, examples of pipeline profiles of interest include: directional drilling and crossings of waterways, highways, railroads, pipelines, other utilities, culverts, and landfills.
Inputs/outputs and Defined Length	• Current & historic inputs	Review maps and historic system flows to determine ~~all~~ input points for the pipeline of interest. Production gas might contain higher concentrations of both gas and entrapped contaminants. Recent well treatments might cause an increase in liquids (particularly unspent acid) or solid contaminants. Well treatment fluids might also react with pipeline debris, creating additional problems. Storage field delivery locations might affect internal corrosion downstream, especially during withdrawal season. Comingled gas might reduce corrosion effects.
	• Current & historic outputs	Major withdrawal points ~~could~~ might reduce gas velocity downstream. Review maps and system flow models, if available, to determine all significant withdrawal points. Examples of withdrawal points include feeds to distribution centers, industrial customers, storage fields, and large load commercial customers. Also, consider the seasonal nature of withdrawal points. Individual residential customers do not have a significant effect on flow velocity and critical angles.
	• Pipeline segment length between inputs/outputs	
Operating History	• Installation date • Service type • Previously for crude oil or other liquid products? • Flow direction changes • Removed taps	Available reports should be reviewed. Operators may determine that fluid removal systems (e.g., dehydration units, separators, filters) operated by other gas suppliers are sufficient in providing dry gas. Installation date affects the length of time a pipe is exposed to potential corrosion~~.~~, but ICDA might still be feasible if the installation date is unknown.
Upsets	• Chronic vs intermittent upsets, frequency • Nature of liquid • Volume, if known	Upsets or bypass of fluid removal systems might introduce water, glycol, or other contaminants into the pipeline.
Type of dehydration	Was glycol dehydration used?	
Hydrotest information	• Past presence of water • Hydrotest water quality data	Pipelines that have been recently hydrotested might still contain water in locations downstream of critical angles. Source of the water is also a ~~concern.~~ consideration; treated municipal water is less likely to cause corrosion than water taken

		from a stream or lake. Consideration should be given to check the moisture content of the pipeline.
Leaks/failures	Leak/failure history	Leak data should be reviewed for evidence of internal corrosion.
Pressure	• Typical minimum operating pressure • Typical maximum operating pressure	Pressure affects gas density, which influences gas velocity and the critical angle.
Flow rate	• Maximum & minimum flow rates at minimum & maximum operating pressures • Periods of low/no flow	Gas flow rate is a major factor in determining how far electrolytes will travel in a pipeline. Changes in flow velocity might allow liquids to accumulate. Flow velocity is a critical factor in determining where fluid might collect in a pipeline system. High winter velocities might clean lines, while low summer velocities might allow liquids to accumulate. Line diameter variations change velocity.
Temperature	• Ambient soil temperature • Compressor discharge • Special environment (e.g. river crossing, aerial pipeline) exists	Corrosion rates double with a 10-degree temperature increase. Hot gas or warm fluids (such as those produced from a deep well or a compressor station) ~~can~~ might increase the risk of internal corrosion.
Water vapor	Water vapor dew point	
Gas quality	• Gas & liquid analyses • Bacteria testing results for the pipeline • Bacteria testing results on shipper & delivery laterals • Location of analyses relative to ICDA location	
Corrosion inhibitor	Chemical injection, type & dose	Corrosion treatments (e.g., biocides or corrosion inhibitors) might not be evenly dispersed throughout the pipeline. For example, the treatment might inhibit corrosion at the first low point, but not at points farther downstream. If internal corrosion inhibitors are used, the operator may need to conduct additional examinations or verify whether the treatment is effective throughout the ICDA region.
Corrosion monitoring	• Monitoring types (e.g., weight loss coupons, probes), locations & results • Non-destructive inspection results.	~~All~~ Available reports should be reviewed. If internal corrosion is present downstream of the critical angle, then ICDA might not be feasible.
Repair / maintenance data	• Presence of solids, anomalies, • Analysis sludge or liquids removed, either using cleaning pig or equipment such as liquid separators, hydrators, etc. • Bacteria test results from removed products • Corrosivity analyses	Prior sampling data provides an indication of whether conditions support internal corrosion. All available reports should be reviewed. Gas sources should be considered. One formation might produce gas with higher H_2S concentrations than another, so the source of gas should be considered. Liquid analysis ~~could~~ might help determine whether corrosive conditions exist. Operators should determine whether accumulations of solids are significant enough to influence the validity of ICDA results. Solids analysis might also indicate type or cause of

		internal corrosion (e.g., carbonate solids might indicate high CO_2 concentrations in gas, and sulfides might indicate microbiologically influenced corrosion (MIC)).
	• Internal pipe Inspections • Nondestructive examination (NDE)	All available prior inspection reports should be reviewed. Determine if internal corrosion has been detected. Clock position of prior internal corrosion might help determine ICDA feasibility. The location of internal corrosion (e.g., bottom or top of pipe) might provide information regarding the mechanism of corrosion.
	• Cleaning pig location, frequency	Cleaning pigs might push fluid past the critical angle. Routine use of cleaning pigs might affect ICDA. The operator should provide technical justification when ICDA is applied to a pipeline that has a history of using cleaning pigs. For example, the justification may need to address how an operator is evaluating low points other than those near the critical angle.
	• Repair and replacement	
Other internal corrosion data	As defined by the pipeline operator.	

TABLE 192.927i

~~INFORMATION FOR ICDA~~		
~~Data Element~~	**~~ICDA Influence~~**	**~~Key Decision Points & Comments~~**
~~Installation date~~	~~Affects the length of time a pipe is exposed to potential corrosion.~~	~~ICDA can be conducted if installation date is unknown.~~
~~Pipe inspection reports~~	~~Provide data on prior internal corrosion.~~	~~All available reports should be reviewed. Determine if internal corrosion has been detected. Clock position of prior internal corrosion may help determine ICDA feasibility. The location of internal corrosion (e.g., bottom or top of pipe) may provide information regarding the mechanism of corrosion.~~
~~Leak history~~	~~Provides data on prior internal corrosion.~~	~~Leak data should be reviewed for evidence of internal corrosion.~~
~~Wall thickness~~	~~Affects the remaining strength and has a minor effect on the critical angle.~~	~~Wall thickness records may be contained in work order files or other historical files. If actual wall thickness is unknown, the operator should assign a thinner wall thickness based on historical data. Changes in wall thickness may affect ICDA regions.~~
~~Diameter~~	~~Affects the remaining strength calculations and is a major factor in determining critical angles.~~	~~Diameter records may be contained in work order files, mapping system, or other historical files. If pipe diameter is unknown, confirmation of diameter should be performed prior to conducting ICDA.~~
~~Internal coating~~	~~Internal coating will inhibit corrosion.~~	~~Internal coating makes it difficult to determine where corrosion may occur and may make ICDA unsuitable.~~
~~Past hydrostatic test information~~	~~Inadequate cleaning may have left water in the pipe.~~	~~Pipelines that have been recently hydrotested may still contain water in locations downstream of critical angles. Source of the water is also a concern.~~

		~~Treated municipal water is less likely to cause corrosion than water taken from a stream or lake. Consideration should be given to check the moisture content of the pipeline.~~
~~Gas, liquid, and solids analysis, including bacterial test results~~	~~Prior sampling data provides an indication of whether conditions support internal corrosion.~~	~~All available reports should be reviewed. Gas sources should be considered. One formation may produce gas with higher H_2S concentrations than another, so the source of gas should be considered. Liquid analysis could help determine whether corrosive conditions exist.~~ ~~Operators should determine whether accumulations of solids are significant enough to influence the validity of ICDA results. Solids analysis may also indicate type or cause of internal corrosion (e.g., carbonate solids may indicate high CO_2 concentrations in gas, and sulfides may indicate microbiologically influenced corrosion (MIC)). See NACE SP0206, Paragraph 3.3.7.~~
~~Internal corrosion probes and coupons~~	~~Weight loss coupons or probes are used to monitor corrosion rates.~~	~~All available reports should be reviewed. If internal corrosion is present downstream of the critical angle, then ICDA may not be feasible.~~
~~Flow velocity~~	~~Gas flow rate is a major factor in determining how far electrolytes will travel in a pipeline. Changes in flow velocity might allow liquids to accumulate.~~	~~Flow velocity is a critical factor in determining where fluid may collect in a pipeline system. High winter velocities might clean lines, while low summer velocities might allow liquids to accumulate. Line diameter variations change velocity.~~
~~Operating pressure~~	~~Operating pressure affects the flow velocity and operating stress level.~~	~~Pressure affects gas density, which influences gas velocity and the critical angle.~~
~~Proximity to treatment facilities and compressor stations~~	~~Hot gas coming from a compressor station can speed up corrosion rates.~~	~~Corrosion rates double with a 10-degree temperature increase. Hot gas or warm fluids (such as those produced from a deep well) will increase the risk of internal corrosion.~~
~~Operating stress level~~	~~Stress level is a major factor in determining risk and remaining life.~~	~~If pipe grade is unknown, conservative assumptions should be made. See §192.107(b)(2).~~
~~Location of all gas input points~~	~~Gas input locations determine ICDA regions.~~	~~Review maps and historic system flows to determine all input points for the pipeline of interest. Production gas may contain higher concentrations of both gas and entrapped contaminants. Recent well treatments may cause an increase in liquids (particularly unspent acid) or solid contaminants. Well treatment fluids may also react with pipeline debris, creating additional problems. Storage field delivery locations may affect internal corrosion downstream, especially during withdrawal season. Comingled gas may reduce corrosion effects.~~
~~Location of all gas withdrawal points~~	~~Major withdrawal points could reduce gas velocity downstream.~~	~~Review maps and system flow models, if available, to determine all significant withdrawal points. Examples of withdrawal points include feeds to distribution centers, industrial customers, storage fields, and large load commercial customers. Also, consider the seasonal nature of withdrawal points. Individual~~

		~~residential customers do not have a significant effect on flow velocity and critical angles.~~
~~Location of drips, valves, dead legs, freeze locations, or other features~~	~~Drips, valves, dead legs, tapping fittings, low spots, and other features are locations where fluid may collect.~~	~~Review maps, system flow models, if available, and as-built drawings to determine locations. These points might require direct examination if they are on pipe within an HCA.~~
~~Elevation profile, including low spots and streams~~	~~Used to determine angle of inclination.~~	~~Elevation profiles may be obtained using GPS and depth of cover or by using topographic maps. Changes in depth of cover must be considered when determining the elevation profile. Due to deeper burial depths, examples of pipeline profiles of interest include: directional drilling and crossings of waterways, highways, railroads, pipelines, other utilities, culverts, and landfills.~~
~~Operating history indicating historic upsets in gas conditions~~	~~Upsets or bypass of fluid removal systems might introduce water, glycol, or other contaminants into the pipeline.~~	~~Available reports should be reviewed. Operators may determine that fluid removal systems (e.g., dehydration units, separators, filters) operated by other gas suppliers are sufficient in providing dry gas.~~
~~Use of cleaning pigs for liquid removal~~	~~Cleaning pigs might push fluid past the critical angle.~~	~~Routine use of cleaning pigs might affect ICDA. The operator should provide technical justification when ICDA is applied to a pipeline that has a history of using cleaning pigs. For example, the justification may need to address how an operator is evaluating low points other than those near the critical angle.~~
~~Internal corrosion treatments~~	~~The effectiveness of treatments may not be uniform along a pipeline.~~	~~Corrosion treatments (e.g., biocides or corrosion inhibitors) may not be evenly dispersed throughout the pipeline. For example, the treatment might inhibit corrosion at the first low point, but not at points farther downstream. If internal corrosion inhibitors are used, the operator may need to conduct additional examinations or verify whether the treatment is effective throughout the ICDA region.~~

~~Table 192.927i~~

(d) Subject Matter Experts (SMEs) may be used to gather and evaluate operating experience data that would provide additional information regarding low points and historic upsets in gas conditions, locations where these low points or upsets have occurred, and any evidence of corrosion damage resulting from low points or upset conditions.

3.2 ICDA feasibility.

A feasibility study must be performed in accordance with NACE SP0206, Section 3.3 and results documented (§192.927(c)(2)). ~~Data and information collected must be integrated and evaluated to determine the feasibility of using ICDA on covered segments (§192.927(c)(1)).~~ The indirect inspection step of ICDA process requires pipeline-specific data not assumed pipeline or operational data (§192.927(c)(2)). If sufficient data is not available or cannot be collected ~~for an ICDA region to support the pre-assessment or step~~, ICDA ~~may~~ might not be feasible.

The following are examples of criteria used in determining that ICDA is not feasible.

(a) Key data, such as inside diameter, elevation profile, or ~~and~~ gas velocity, are not available ~~or reasonable assumptions cannot be made~~.

(1) Data assumptions may be made for characteristics that are not critical to the flow model, elevation profile, or critical angle determination steps in the Indirect Inspection phase.

(2) Additional information such as ASME B31.8S, Appendix A2 may also be incorporated into the feasibility review.

(b) A pipeline that normally contains an electrolyte in the gas stream (i.e., a wet-gas system).

(c) A pipeline that has been previously converted from transporting other products (e.g., crude oil, refined products) unless it is demonstrated either that internal corrosion did not occur in the previous service or that previous damage has been separately assessed.

(d) A pipeline with a history of pigging that could distribute liquids in a way that is not predicted by ICDA. The operator should provide technical justification whenever ICDA is applied to a pipeline that has a history of using cleaning pigs (NACE SP0206, Paragraph 3.3.5). An example would be lines with liquids that do not contain an electrolyte (e.g., drip gas).

(e) A pipeline treated with corrosion inhibitors. The use of inhibitor ~~may~~ might preclude application of ICDA because the effectiveness of the inhibitor might not be uniform along the pipeline length.

(f) The pipeline has an internal coating that is intended to provide corrosion protection. The use of internal coating ~~may~~ might preclude application of ICDA because the effectiveness of the coating might not be uniform along the pipeline length.

(g) Pipelines that contain accumulations of solids, sludge, biofilm/biomass, or scale. Such accumulations ~~may~~ might affect the validity of this ICDA process. ~~See NACE SP0206, Paragraph 3.3.7.~~

(h) Pipelines with history of top-of-the-pipe (12 o'clock position) corrosion, as could occur from condensation of liquids in the gas stream.

4 ~~IDENTIFICATION OF ICDA REGIONS~~INDIRECT INSPECTION

4.1 Region Identification.

~~(a)~~ An ICDA region ~~is a defined length of a pipeline that~~ begins at the location where a liquid containing an electrolyte ~~may~~ might first enter the pipeline. The region continues until another input might introduce water or electrolyte and for which physical characteristics and flow are similar.

(a) Examples of beginnings include the following.
  (1) Delivery point or take station.
  (2) Production well.
  (3) Connection with another pipeline.
  (4) Storage well.

(b) A significant change in water or flow characteristics or the operating history of the segment might trigger a new ICDA region.

~~(b) In accordance with §192.927(c)(2), an ICDA region encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. In accordance with the model in GRI-02/0057, the critical angle determines the extent where the corrosion will occur. Thus, an ICDA region begins at an input point and ends at the next input point. where the first pipeline inclination angle exceeds the critical angle.~~

(c) In a pipeline where bi-directional flow exists or has existed and where electrolytes are present in the gas from both source locations, it is required to consider each flow direction when determining the ICDA regions ~~(see GRI-02/0057)~~.

(d) In accordance with §192.927(c)(2), an operator's ICDA plan must identify all ICDA regions. An ICDA region may encompass one or more covered segments. A covered segment may also be located in more than one ICDA region.

(e) Data specific to the pipeline under evaluation itself must be applied during the Indirect Inspection step, both for identifying regions and for performing critical inclination angles. ICDA might not be feasible if accurate and reliable gas flow velocity, upset history, and pipeline elevation profile are not available.

~~5 IDENTIFICATION OF LOCATIONS FOR EXCAVATION AND DIRECT EXAMINATION~~

~~The identification of excavation locations is based on the following.~~

~~(a) Flow-modeling to determine the critical angle.~~

~~(b) Developing a pipeline elevation profile.~~

~~(c) Identifying sites where internal corrosion may likely occur.~~

~~Direct examination is then conducted in order to assess the internal surface of the pipeline for corrosion. If corrosion is found, evaluations of remaining strength in the pipe wall and mitigation are required (§192.927(c)(3)(i)).~~

~~5.1~~ 4.2 Critical angle determination

(a) The critical angle is defined as the smallest angle determined by dry gas ICDA flow modeling at which liquid carryover will not occur under stratified flow conditions. ~~In accordance with §192.927(c)(2), an operator is required to use the model as defined in GRI-02/0057, or an equivalent model, to determine the critical angle for each ICDA region that includes a covered segment. See NACE SP0206 ICDA for an example of an equivalent model.~~ Critical inclination angle depends upon gas flow velocity and pipeline characteristics.

(b) ~~To calculate the critical angle using the model contained in GRI-02/0057, the operator needs to determine the following information (§192.927(c)(2)).~~ For dry gas ICDA, the critical inclination angle must be calculated per NACE SP0206. This methodology does not apply to wet gas; alternative formulae and considerations must be used for non-dry gas applications. For the calculation, the operator should determine the following information.

(1) Inside diameter and changes to diameter.
(2) Gas temperature.
(3) Operating pressure.
(4) Liquid density.
(5) Gas density.
(6) Gas velocity.

(c) Where pipeline operating conditions fluctuate (e.g., pressure, temperature, ~~or~~ flow direction), the operator should consider calculating multiple angles for the appropriate fluctuating conditions to determine if the location of the critical angle changes. Increased flow might cause liquids to be transported further downstream than during normal flow, introducing the possibility of different holdup locations. Scenarios may include the following.

(1) Normal flow conditions.
(2) Seasonal flow variations.
(3) Known upset conditions.

~~5.2~~ 4.3 Pipeline profile.

(a) The pipeline profile reflects elevation changes along the pipeline.

(1) The pipeline inclination profile should consider the accuracy, reliability, and uncertainty of elevation profile data. Additional or more closely spaced readings at locations likely to have elevation changes (e.g., crossings, valves, other appurtenances) can improve profile accuracy.
(2) When overlaid with topographic information, pipeline centerline accuracy can impact profile accuracy.

(b) Data used in determining a pipeline profile may include the following.

(1) *Surface elevations.*
Surface elevations may be obtained from the following.
(i) Elevation survey of the land over the pipeline.
(ii) Land-based data such as topographic maps.

Elevation measurements should be taken at intervals that capture relevant changes in the surface profile. The minimum interval depends upon the specific pipeline being evaluated, the terrain, and other features. The intervals at known pipe route obstructions (e.g., roadways, rivers) should be decreased in order to capture specific pipeline fittings (e.g., vertical elbows, pipe bends). The accuracy and uncertainty of topographic data might depend upon the granularity of the underlying dataset.

(2) *Depth of cover.*
An operator should determine depth of cover, which can be determined by the following.
(i) Using average depth of cover considering possible changes based on construction records and inspection reports.

(ii) Performing a depth-of-cover survey. Accuracy of depth of cover measurements might depend on tool tolerances as well as accuracy of centerline data and spacing of measurements.

(3) *In-Line Inspection Mapping Tools.*
In-line inspection tools with gyroscopic mapping capabilities can generate elevation profiles without direct topographic or depth of cover measurements. Tool tolerance and accuracy specifications are provided by the tool vendor.

(4) *Digital Elevation Model (DEM).*
A Digital Elevation Model (DEM) might be created from elevation data collected as part of the indirect inspection process or might already exist. In areas with significant topographic changes, consider whether previously generated DEMs are still a valid reflection of landscape.

(c) Determining profile.
Subtracting the depth-of-cover data from the surface elevation determines the pipeline profile. The degree of accuracy required in the calculation of the pipeline profile is relative to the critical angle size. For very small critical angles (e.g., 1 degree) the operator should consider increasing the precision of the pipeline profile. Methods to increase the precision include the following.
(1) Using more accurate elevation measurement techniques.
(2) Using survey-grade GPS for stationing.
(3) Decreasing the spacing between elevation survey measurement points.
(4) Potholing to measure the depth of the pipeline.
(5) Using an instrument (e.g., current attenuation) to determine the depth of cover.

~~5.3~~ 4.4 Pipeline inclination angle.

The pipeline inclination angle is the angle (measured in degrees) resulting from an increase in elevation between two pipeline profile data points. It is calculated using the following equation.

$$\theta_i = \arcsin \frac{\Delta(\text{elevation})}{\Delta(\text{distance})}$$

[Editorial Note: There is no change being proposed to equation in Guide, parentheses around the fraction are missing here in TR presentation of equation.]

Where:

θ_i = Angle in degrees
Δ(elevation) = Elevation change, feet
Δ(distance) = Distance change, feet

These pipeline inclination angles shall be established between the profile data points along the length of each identified ICDA region (§192.927(c)(2)). If bi-directional flow exists or has existed within the pipeline, the critical angle needs to be calculated for both directions and compared to the pipeline inclination angles for the appropriate direction. ~~If the first critical angle is upstream of each involved covered segment, ICDA may be discontinued.~~

5 DETAILED EXAMINATION

The identification of excavation locations is based on the following.
(a) Flow-modeling to determine the critical angle.
(b) Developing a pipeline elevation profile.
(c) Identifying sites where internal corrosion might likely occur.

Direct examination is then conducted in order to assess the internal surface of the pipeline for corrosion. If corrosion is found, evaluations of remaining strength in the pipe wall and mitigation are required (§192.927(c)(3)(i)).

5.~~4~~ 1 Identifying excavation location.

The operator is ~~only~~ required to dig and directly examine according to NACE SP0206, Sections 4.4 and 4.5 ~~within a covered segment (§192.927(c)(3))~~, the location of which can be found by the following.

~~(a) Comparing the critical angle with the pipeline inclination angles. If no angles exceed the critical angle, the largest inclination angle will be used~~

(~~b~~ a) Determining the first critical angle location downstream from beginning of the ICDA region.

(~~a~~ b) Comparing the critical angle with the pipeline inclination angles. If all inclinations have angles smaller than critical, the largest angles are used in the analysis in descending order.

~~(c) Determining the location(s) of the covered segments relative to the first critical angle.~~

(~~d~~ c) Perform excavations at the following locations.

(1) The first pipe inclination downstream from the beginning of the region greater than the largest critical inclination angle determined by the range of operating conditions and the flow modeling results. If all inclinations have angles smaller than critical, use the angle of greatest inclination within the DG-ICDA region. ~~The low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region.~~

(2) A second location further downstream, with inclination greater than the critical angle ~~within a covered segment, near the end of the ICDA region~~. If all pipe inclinations have angles smaller than critical, the operator should choose the angle of greatest inclination ~~within the covered segment~~.

(3) A third examination at the next location with inclination greater than the critical angle serves as validation of the assessment.

(4) Two consecutive locations must be found free from internal corrosion to complete the assessment. Additional locations might need to be evaluated to meet this criterion (per NACE SP0206).

(~~e~~ d) If the ICDA region ends before the start of the covered segment (pipeline inclination angle that exceeds critical angle is upstream of covered segment), the first two steps of the ICDA process can be used as a threat screening tool. Since the covered segment is downstream of a critical angle, electrolytes will not reach the covered segment and internal corrosion is not a threat to the covered segment. If there is bidirectional flow, both flow directions must be considered before determining the applicability of internal corrosion as a threat (§192.927(c)(1)(ii) and (iii)).

~~(f) Examples are provided in 5.5 below to show the relationship between ICDA regions, covered segments, and proposed excavation locations.~~

~~*5.5 Examples.*~~

~~(a) Example 1 Covered Segment Downstream of Critical Angle.~~

~~*{Remove figure in Guide; not shown here.}*~~

~~**FIGURE 192.927A**~~

~~Figure 192.927A illustrates a pipe inclination angle greater than the critical angle that is located upstream of the covered segment. Note that the ICDA region ends at the critical angle because §192.927(c)(2) states the region extends along the area where corrosion may occur. In this example, the threat of internal corrosion can be ruled out downstream from Point "C" if there are no other inputs; thus, the ICDA integrity assessment can stop. The operator should continue to monitor the operating parameters of the system to determine if the critical angle or pipe inclination angle changes.~~

~~(b) Example 2 Covered Segment Includes Critical Angle.~~

~~*{Remove figure in Guide; not shown here.}*~~

~~**FIGURE 192.927B**~~

~~(1) Figure 192.927B illustrates a scenario where the first pipe inclination angle greater than critical angle (Point "C") is located within the covered segment and ICDA region. Point "B" is required to be excavated because it is the first low point near the beginning of the~~

~~covered segment. Point "C" is required to be excavated because it is within the covered segment, near the end of the ICDA region, and at a location where the inclination angle is greater than critical angle (see §192.927(c)(3)).~~

~~(2) If no corrosion is found at Points "B" and "C," then internal corrosion is not a threat to the covered segment. The operator should continue to monitor the operating parameters of the system to determine if any pipe inclination angle changes occur due to construction or maintenance activity on the covered segment.~~

~~(3) If corrosion is found at Point "B" or Point "C," the operator is required (§192.927(c)(4)(ii)) to conduct additional excavations or assess the covered segment by another method. If additional excavations are to be used, the length of the excavations and Point "A" or "B" could be extended to look for additional internal corrosion or another location could be examined. This regulation also requires that if corrosion is found (§192.927(c)(3)(iii)), non-covered segments with the same operating conditions must be evaluated and remediated. To address the non-covered segment, Point "A" should be excavated and examined.~~

~~(c) Example 3 Covered Segment Upstream of Critical Angle.~~

~~*{Remove figure in Guide; not shown here.}*~~

~~**FIGURE 192.927C**~~

~~(1) Figure 192.927C illustrates a pipe inclination angle greater than the critical angle located downstream of the covered segment. Excavations are required at Point "A" (the first upstream low point) and at Point "B" (a second downstream point within the covered segment). If corrosion is not found at either location, then internal corrosion is not a current threat to the covered segment. The operator should continue to monitor the operating parameters of the system to determine if any pipe inclination angle changes occur due to construction or maintenance activity on the covered segment.~~

~~(2) If corrosion is found at Point "A" or Point "B," the operator is required (§192.927(c)(4)(ii)) to conduct additional excavations or assess the covered segment by another method. If additional excavations are to be used, the length of the excavations and Point "A" or "B" could be extended to look for additional internal corrosion, or another location could be examined. This regulation also requires that if corrosion is found (§192.917(e)(5)), non-covered segments with the same operating conditions must be evaluated and remediated. To address the non-covered segment, Point "C" could be excavated and examined.~~

5.~~6~~ 2 Direct examination.

The objective of the ICDA direct examination is to determine if internal corrosion exists at the locations identified in 5.~~4~~ 1 above. ICDA required excavations may be used as ECDA validation digs if applicable conditions are analyzed and documented. In addition, ECDA required excavations may be used for ICDA validation digs if the conditions are analyzed and documented.

(a) Determining extent of excavation.

(1) For a short elevation drop associated with a feature (e.g., a road crossing), water accumulation commonly occurs on the short uphill segment, indicating a limited section of pipe to excavate.

(2) Where a long, constant up-slope exists, such as a hill or a rise, identification of the liquid holdup location within the section of pipe ~~may~~ might be more difficult. It has been shown that in this situation, there is the possibility that the liquid will be pushed up the slope where it will roll back on itself and, as such, ~~may~~ might not settle to the bottom of the angle if velocity is maintained. In this case, the operator may consider the use of assessment methods that provide a larger "view" of the situation. For example, a long-range guided wave evaluation may be made from an excavation up the slope from the base of the critical angle so that internal corrosion may be detected from the bottom of the angle, past the test point, and forward up the slope. If internal corrosion is identified, then additional direct examination should be performed at its apparent location with detailed measurements of wall loss made as described in 5.6(b) below.

(3) Larger excavation areas might be advisable if the low point or critical angle site determination is less accurate or has greater uncertainty.

(b) Metal loss measurements.

...

(c) Corrosion found.

Section §192.927(c)(3) requires that, when corrosion is found, the severity of the defect (remaining strength) needs to be evaluated and the defect addressed ~~in accordance with §192.933~~. The direct examination step should continue with the following activities.

...

(d) Remaining strength.

...

(e) Evaluation of cause.

...

(f) Mitigation.

(1) Replacement or repair should be made with materials and processes that are suitable for the pipeline operating conditions (see §§192.476, 192.487, and 192.713). Any replacement or repair made should be done in conjunction with the mitigation and prevention of internal corrosion (see guide material under §192.476). Unless the corrosion source is mitigated, pipe requiring repair or replacement will require continued monitoring in each covered segment where the internal corrosion has been identified.

(2) When internal corrosion is found, the operator must expand the detailed examination program to determine all locations within the ICDA region that have internal corrosion (§192.927(c)(3)(ii)).

(i) If internal corrosion identified is outside a covered segment, the expanded program must include a low point within the covered segment nearest the beginning of the ICDA region.

(ii) If internal corrosion identified is outside a covered segment, the expanded program must also include a second location within the covered segment.

(iii) The expanded program examinations cannot repurpose examinations made as part of the original detailed examination. If both required expansion locations have already been examined, an additional two locations must be selected within the covered segment.

(~~2~~ 3) When internal corrosion is found, the operator is required (§192.927(c)(3)(iii)) to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system. This applies to systems having similar characteristics to the ICDA region containing the covered segment in which corrosion was found. As appropriate, the operator is to remediate the conditions found in accordance with §192.933 or §192.485 in addition to §192.714. Examples of similar characteristics include the following.

(i) ...

...

6 POST-ASSESSMENT EVALUATION AND MONITORING

The post-assessment evaluation and monitoring step involves the integration and analysis of data collected from the previous three steps to determine the effectiveness of the ICDA process, establish reassessment, and schedule monitoring of covered segments where internal corrosion has been found.

6.1 Determining ICDA effectiveness.

The effectiveness of the ICDA process is determined by the correlation between detection and nondetection of corrosion at the location where internal corrosion is predicted to occur. ICDA is also considered to be effective if pipeline history and current operating conditions indicate internal corrosion is not expected and no corrosion is found in the direct examination step.

(a) The operator has one year to complete its effectiveness evaluation. (§192.927(c)(4)(i))

(b) If actual corrosion locations do not align with predicted water hold-up locations, either the flow model, or critical angle determination might be an issue.

(1) If internal corrosion is found throughout the pipeline (e.g., not at low points), or corrosion is found on top of the pipe, ICDA feasibility should be reevaluated.
(2) If corrosion is found downstream of the first critical angle, then the determination of the critical angle should be reevaluated.

6.2 Determining reassessment intervals.

In accordance with §192.927(c)(4), the operator is required to determine if the covered segment should be reassessed at more frequent intervals than specified in §192.939. The following process determines reassessment intervals for ICDA (§192.939(a)(3)).

(a) Remaining defect size estimation.
...
(b) Remaining life determination.
An operator should use sound engineering analysis to estimate the remaining life of the largest remaining defect. If no corrosion defects are found, then the remaining life is the same as new pipe. The operator may use the formula provided in NACE SP0502~~-2010~~, Paragraph 6.7.2.1 (see listing in §192.7, not IBR for §192.927), or an equivalent equation such as the following.

Remaining Life Equation:
...
(c) Corrosion rate calculation.
(1) The corrosion growth rate should be based on sound engineering analysis. If available, an operator should use actual corrosion rate information for the ICDA region. Actual corrosion rates may be determined by direct measurement of wall thickness as a function of time for the pipeline in question. An operator should review data collected in the pre-assessment records to determine if this information is available. For example, data may include recent measurement of pipe wall loss (e.g., from direct examination). The wall loss divided by the number of years the pipeline has been in service ~~may~~ might provide an adequate corrosion rate.
(2) Acceptable alternatives to estimate the corrosion rate are referenced in NACE SP0206, Paragraph 6.3.1.
(d) Reassessment interval calculation.
(1) When corrosion defects are found during direct examinations, the maximum reassessment interval for each ICDA region is the lower of the following.
(i) One-half the remaining life, or
(ii) The reassessment interval allowed in ASME B31.8S (see §192.7 for IBR), Section 5, Table 3 (see Table §192.939iv of the guide material under §192.939).
Note: For the ICDA process, the meaning of the phrase "sample of indications" as used in ASME B31.8S, Section 5, Table 3 is considered to be the direct examination of the pipe at the first upstream critical angle.
(2) For pipelines operating at 30% or more of SMYS and the ICDA reassessment interval exceeds 7 years according to ASME B31.8S, then Confirmatory Direct Assessment (CDA) or other assessments such as ILI, ICDA, or pressure testing is required to be performed at intervals not exceeding 7 years (§192.939).
(3) For pipelines operating at less than 30% SMYS, a low stress reassessment may be conducted (see guide material under §192.941). Example: A pipeline operates at a hoop stress of 25% SMYS and the half-life analysis calculates to be 23 years. In accordance with §192.939(b)(6), the maximum reassessment interval is 20 years. Therefore, the required reassessment interval for a full integrity assessment is 20 years. Note that either CDA is required every 7 years or the operator is required to follow the requirements of a low stress reassessment in accordance with §192.941.

6.3 Continual monitoring.

(a) ...
(b) If evidence of corrosion products (e.g., pitted corrosion probe, deposits, scale) is found during the monitoring of the covered segment, prompt action is required to be taken to implement at least one of the following actions (§192.927(c)(4)(~~ii~~ iii)).

(1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe. The operator should perform a direct examination in accordance with 5.~~6~~ 2 above. See 5.~~4~~ 1 above for identifying the direct examination locations.

(2) Assess the covered segment using another integrity assessment method allowed by Subpart O.

7 FIRST-TIME ICDA APPLICATION

When conducting ICDA for the first time on a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with that ICDA region. (§192.927(c)(3)).

(a) One must be at the first low point and the other further downstream.

(b) For this determination, separate HCA segments which abut one another but with separate identifiers within the operator's tracking or GIS system can be treated as a single covered segment for the purposes of identifying exam locations. Ultrasonic thickness measurements, radiography, or other examination techniques for detection of wall loss due to internal corrosion might be used.

~~more restrictive criteria is required (§192.927(5)(ii)). Examples of more restrictive criteria include the following.~~

~~(a) Pre-assessment.~~

~~(1) Analyzing additional data elements (e.g., data not listed in Table 192.927i), such as temperature, or other internal corrosion data defined by the operator.~~

~~(2) Obtaining and analyzing upset information from both suppliers and other upstream operators with the same supplier.~~

~~(b) Region identification.~~

~~(1) For identification of locations for excavation and direct examination, taking additional data to better define the inclination profile of a pipeline such as decreasing the distance between survey points.~~

~~(2) Running the flow model at a range of flow rates to determine the sensitivity of the critical angle to various flow conditions experienced over time.~~

~~(c) Identification of locations for excavation and direct examination.~~

~~(1) Performing additional excavations.~~

~~(2) Extending the length of an excavation to evaluate more pipe.~~

~~(3) Using multiple NDT methods to inspect the pipe.~~

~~(d) Post-assessment and monitoring~~

~~(1) Periodically analyzing gas and liquid samples.~~

~~(2) Installing internal corrosion monitoring equipment, even if no internal corrosion is found.~~

~~(3) Increasing the frequency of monitoring gas samples, liquid samples, or corrosion detection devices if corrosion is found.~~

~~(e) Other criteria the operator deems applicable to the pipeline conditions.~~

8 RECORDKEEPING

(a) ICDA records that are pertinent to the pre-assessment, indirect inspection ~~ICDA region identification~~, ~~identification of locations for excavation and direct~~ detailed examination, ~~and~~ post assessment, and monitoring steps should be documented in a clear, concise, and workable manner.

...

9 REFERENCES

(a) ASME B31.8S, "Managing System Integrity of Gas Pipelines."

~~(b) GRI-02/0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology."~~

(~~c~~ b) NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)."

(c) NACE SP0110, "Wet Gas Internal Corrosion Direct Assessment."

(d) NACE SP0502, "Pipeline External Corrosion Direct Assessment Methodology."

(e) PHMSA-OPS, "Gas Integrity Management Protocols with Guidance," Protocol Area D, DA Plan.

GMA G-192-1

1.9 CORROSION RELATED (Continued)		
...	...	...
NACE SP0110	Wet Gas Internal Corrosion Direct Assessment	§192.927
...	...	...