Note: The changes made in the regulations are highlighted in yellow color wherein the struck off portion is deleted and the remaining portion is added in the regulations. The text appearing in blue color indicates shifting of clauses within the regulations.

PETROLEUM AND NATURAL GAS REGULATORY BOARD
NOTIFICATION

New Delhi, the 5th November, 2012

F.No. Infra/IM/NGPL/12010.-In exercise of the powers conferred by section 61 of the Petroleum and Natural Gas Regulatory Act, 2006 (19 of 2006), the Petroleum and Natural Gas Regulatory Board hereby makes the following regulations, namely:-

1. Short title and commencement.

(1) These regulations may be called the Petroleum and Natural Gas Regulatory Board (Integrity Management System for Natural gas pipelines) Regulations, 2012.

(2) They shall come into force on the date of their publication in the Official Gazette.

2. Definitions.

(1) In these regulations, unless the context otherwise requires, -

(a) "Act" means the Petroleum and Natural Gas Regulatory Board Act, 2006;

(b) "Board" means the Petroleum and Natural Gas Regulatory Board established under sub-section (1) of section 3 of the Act;

(c) "natural gas pipeline" means the pipeline as defined under the Petroleum and Natural Gas Regulatory Board (Authorizing Entities to Lay, Build, Operate or Expand Natural gas pipelines) Regulations, 2008;

(d) "operator" means an entity that operates natural gas pipeline network with the authorization of the Board;

(e) ~~"risk" means the risk as defined under the Petroleum and Natural Gas Regulatory Board (Codes of Practices for Emergency Response and Disaster Management Plan (ERDMP) Regulations, 2010~~ "risk" is the measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences;

(f) ~~"risk analysis" means the risk analysis as defined under the Petroleum and Natural Gas Regulatory Board (Codes of Practices for Emergency Response and Disaster Management Plan (ERDMP) Regulations, 2010~~;

(g) "risk assessment" means ~~the risk assessment analysis as defined under the Petroleum and Natural Gas Regulatory Board (Codes of Practices for Emergency Response and Disaster Management Plan (ERDMP) Regulations, 2010~~ systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and can be performed at varying levels of detail depending on the operator's objectives;

(h) "risk management" means ~~the risk management as defined under the Petroleum and Natural Gas Regulatory Board (Codes of Practices for Emergency Response and Disaster Management Plan (ERDMP) Regulations, 2010~~ overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved;

(i) "transmission pipeline ~~system~~" means one or more segments of pipeline usually interconnected to form a network that transports gas from a gathering system, the outlet of a gas processing plant or a storage field to a high, medium or low-pressure pipeline system, a large-volume customer or another storage field;

(j) "sub transmission pipeline" means a high pressure pipeline connecting the main natural gas pipeline to the city gate station ~~but is owned by the CGD entity~~;

(k) "spur-line" means a pipeline as defined in the Petroleum and Natural Gas Regulatory Board (Determining Capacity of Petroleum and Petroleum Products and Natural Gas Pipeline) Regulations, 2010;

(l) "Subject Matter Expert (SME)" means an individual who possesses knowledge and experience in the process or discipline ~~he~~ one represents as per ASME B 31Q;

(m) "right of user (ROU) ~~or right of way (ROW)~~" means the area or portion of land within which the pipeline operator or owner has acquired the right through the relevant provisions of law or in accordance with the agreement with the land owner or agency having jurisdiction over the land to lay and operate the natural gas pipelines;

(n) "integrated surveillance system" means the pipeline surveillance for third party encroachment activities along ROU. This may use optical fiber cable, microwaves and satellite as communication systems and could be integrated with SCADA's data;

(o) "Shall" indicates that the provision in which it occurs is mandatory;

(p) "Should" Indicates that the provision in which it occurs is recommendatory but not mandatory;

Other definitions / terminologies used for integrity assessment like anomaly, defect, MAOP etc. not defined above, shall be as defined in ASME 31.8S.

(2) Words and expressions used and not defined in these regulations, but defined in the Act or in the rules or regulations made thereunder, shall have the meanings respectively assigned to them in the Act or in the rules or regulations, as the case may be.

3. Applicability.

These regulations shall apply to all the entities laying, building, operating or expanding natural gas pipelines.

4. Scope.

These regulations shall cover all the existing and new natural gas transmission pipelines, spur lines, sub-transmission pipelines (STPL) and dedicated pipelines. This includes the associated facilities required for transportation of natural gas through pipelines ~~that is~~ such as terminals, intermediate pigging facilities, compressor stations, sectionalizing valves etc.

The materials and specifications followed shall be in accordance with Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipeline) Regulations, 2009.

5. Objective.

(1) These regulations outline the basic features and requirements for developing and implementing an effective and efficient integrity management plan for natural gas pipeline system.

(2) These regulations are intended to-

- (a) evaluate the risk associated with natural gas pipelines and effectively allocate resources for prevention, detection and mitigation activities;
- (b) improve the safety of natural gas pipelines so as to protect the personnel, property, public and environment;
- (c) have streamlined and effective operations to minimize the probability of Natural gas pipeline failure.

6. Integrity Management System.

The development and implementation of Integrity Management System for the natural gas pipelines shall be as described in SCHEDULE-1 to SCHEDULE-10 of these regulations.

7. Default and consequences.

(1) Compliance to the provisions of these regulations shall be done through implementation schedule as described in these regulations at Schedule-7 and Schedule-8 in conjunction with Appendix-II.

(2) In case of any shortfall in achieving the implementation schedule of Integrity Management System as specified in these regulations, the entities shall be liable to face the following consequences, namely: -

(i) the entity shall be required to complete each activity within the specified time limit and if there is any deficiency in achieving in one or more of the activities, the entity shall submit a mitigation plan with time schedule ~~within the time limit~~ for acceptance of the Board and make good all short comings within the time agreed by the Board. If the entity fails to complete activities within the specified time limit by the Board, relevant penal provisions of the Act shall apply;

(ii) in case the entity fails to implement the approved Integrity Management System, the Board may issue a notice to defaulting entity allowing it a reasonable time to implement the provisions of Integrity Management System. In case the entity fails to comply within the specified time, the relevant provisions of the Act and regulations shall apply.

8. Requirement under other laws.

It shall be necessary to comply with all statutory rules, regulations and Acts in force as applicable and obtain requisite approvals from the relevant competent authorities for the natural gas pipeline.

9. Miscellaneous.

(1) Through these regulations the uniform application of Integrity Management System is to be ensured for all natural gas pipelines.

(2) Entity operating and maintaining natural gas pipelines shall have ~~the qualified manpower as per three structure as indicated in Appendix-IV~~ a written plan / philosophy of deploying qualified and trained manpower at the installations based on activities required for compliance to this regulation.

(3) These regulations either on suo-motu basis or on the recommendation of concerned sub-committee of natural gas pipelines shall be reviewed by the Board from time to time.

10. Power to remove difficulties.

In the event of the problem faced by the entity in implementing the provisions contained in these regulations, the entity may approach Board for necessary dispensation.

SCHEDULES
(see regulation 6)

SCHEDULE–1

OBJECTIVE

The objective of Pipeline Integrity Management System is to maintain integrity of natural gas pipelines at all times to ensure public safety, protect environment and ensure availability of pipeline to transport gas without interruptions and ~~also~~ minimize ~~business~~ risks associated with accidents and losses. The availability of the Integrity Management System will allow professionals and technicians engaged in integrity tasks to have clearly established work aims and targets in the short, medium and long term, which undoubtedly will enhance their efficiency and satisfaction to attain them.

The Integrity Management System will enable the natural gas pipeline transporter to select an identified system for implementation such that the Integrity Management System will be uniform for all natural gas pipeline entities within the country.

An effective Integrity Management System shall ~~be~~:

- Ensure ~~ing the quality of~~ natural gas pipeline integrity in all areas which have potential for adverse consequences.
- Promote ~~ing~~ a more rigorous and systematic management of natural gas pipeline integrity and mitigating the risk;
- Enhance ~~Increasing~~ the general confidence of the public in the operation of natural gas pipeline.
- Enhance ~~Optimizing~~ the life of the natural gas pipeline with the inbuilt incident investigation and data collection including review by the entity.

SCHEDULE–2

INTRODUCTION TO THE INTEGRITY MANAGEMENT SYSTEM (IMS)

2.1 Every natural gas pipeline operator's primary focus shall be on operation and maintenance of natural gas pipeline in such a way that it would continuously provide un-interrupted services to customers with utmost reliability and safety without any untoward incident which can adversely impact the environment.

2.2 A pipeline Integrity Management System shall provide a comprehensive and structured framework for assessment of pipeline condition, likely threats, risks assessment and mitigation actions to ensure safe and incident free operation of the pipeline system.

2.3 Such a comprehensive integrity management system shall essentially comprise the following elements:

- **Integrity Management Plan (IMP):** This encompasses collection and validation of data, assessment of spectrum of risks, risk ranking, assessment of integrity with respect to risks, risks mitigation, updation of data and reassessment of risk.
- **Performance evaluation of IMP:** This is a mechanism to monitor the effectiveness of integrity management plan adopted and for further improvement.
- **Communication Plan:** This covers a structured plan to regulate information and data exchange within and amongst the internal and external environment.
- **Management of Change:** This is the process to incorporate the system changes (technical, physical, procedural and organization changes) into integrity management plan to update the integrity management plan.
- **Quality ~~Control~~ Plan:** This is the process to establish the requirements of quality in execution of the processes defined in the integrity management plan.

Note: These elements have further been detailed in Schedule-6.

SCHEDULE–3

DESCRIPTION OF NATURAL GAS PIPELINE SYSTEM

3.1 **PHYSICAL DESCRIPTION:** Description of natural gas pipeline should include specific description of the pipelines, compressor~~s~~ stations, valve~~s~~ stations and ~~with respect to design specifications, length,~~ major installations details such as:

- 3.1.1 ~~Trunk~~ Transmission Pipeline
- 3.1.2 Spur-pipelines
- 3.1.3 Sectionalizing Valve Stations
- 3.1.4 Intermediate Pigging Stations
- 3.1.5 Tap-Off Stations
- 3.1.6 Compressor Stations
- 3.1.7 Control ~~Stations~~ Rooms
- 3.1.8 Electrical System ~~depending upon Captive power generation or Grid-power.~~
- 3.1.9 Cathodic Protection System
- 3.1.10 Telecom / SCADA
- 3.1.11 Safety Equipments
- 3.1.12 ~~Delivery Stations~~ Dispatch Terminal / Receiving Terminal

3.2 OTHER DESCRIPTION:

- 3.2.1 ROU Details-ROU width and constraints, if any
- 3.2.2 Interfaces with other operators' facilities or pipelines, if any;
- 3.2.3 Historical background of the natural gas pipeline and major modifications and additions carried out in the system, if any;
- 3.2.4 List of the consumers served by the pipelines;
- ~~3.2.5 Inspection updates;~~
- ~~3.2.6 Incident reporting;~~
- ~~3.2.7 Statement of compliance with Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural Gas Pipeline) Regulations, 2009;~~
- ~~3.2.8 Statutory compliances.~~

SCHEDULE–4

SELECTION OF APPROPORIATE INTEGRITY MANAGEMENT SYSTEM

4.1 Integrity Management System for natural gas pipelines could employ either a performance based Integrity Management System or a prescriptive type Integrity Management System. Whereas, natural gas pipeline industry has gathered a reasonably good experience of pipeline operations and as such pipeline industry is fairly mature, a performance based Integrity Management System are appreciated globally. However, where pipeline systems are in developing stage, a prescriptive type Integrity Management System is recommended. Whereas, the performance based Integrity Management System recognizes the experience of the entity which has been operating the pipeline but the prescriptive type Integrity Management System is more rigorous as it considers the worst case scenario of the failures in the pipeline systems and, therefore, worst case scenario for mitigation.

4.2 Though subsequent schedule in these regulations apply to both prescriptive and performance based type of Integrity Management System, present regulations mainly focus on prescriptive aspects in absence of adequate historical Integrity Management System data.

4.3 A prescriptive type of Integrity Management System mandates the implementation of an established process for addressing the risks, their consequences and proven methods for mitigation. It also mandates the in-house development of Integrity Management Plan and Management of Change pertaining to technical aspects. ~~Based on the development of gas pipeline industry in India till date, the preparation of prescriptive type Integrity Management System has been considered for implementation to all natural gas pipelines in India.~~ However, Entity may adopt more rigorous IMP within a prescriptive IMP based on their in-house assessment. Further, as the natural gas pipeline industry matures and gathers sufficient records or data as per the requirements prescribed in the Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications Including Safety Standards for Natural gas pipelines) Regulations, 2009, ~~a review mechanism may be considered by the Board for recommending a Performance Based Integrity Management System for Natural gas pipeline.~~ the Board may consider allowing a performance based IMP during subsequent revisions of IMS document for a network.

SCHEDULE–5

INTEGRITY ASSESSMENT, MONITORING AND SURVEYS

Some of the tools for Integrity assessment, surveys, monitoring & surveillance are provided below. The operator shall employ at least one integrity assessment tool and should use ~~as many~~ all applicable surveys, monitoring & surveillance tools necessary to achieve the IMS for natural gas pipeline. It may be noted that the baseline data for specific measurement should be available with the operator. ~~as a ready-reckoner:~~

The operator of a pipeline system shall develop a chart of most suited integrity assessment tool ~~or method~~, surveys, monitoring & surveillance and ~~assessment~~ interval for each threat/risk and further develop appropriate specifications and quality control plan for such assessment. After establishing effectiveness of assessment, the interval of assessment may be further modified subject to any other code requirement such as Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for natural gas pipelines) Regulations, 2009. A suggested chart is placed at APPENDIX –III

5.1 INTEGRITY ASSESMENT TOOLS

5.1.1 In-Line Inspection

In-line inspection (ILI) is an integrity assessment method used to locate and ~~preliminarily~~ characterize indications, such as, metal loss due to internal / external corrosion & other mechanical damage or deformation.~~, as well as external and internal corrosion in a pipeline. ASME B31.8 S "*Managing System Integrity for Natural gas pipelines*" provides additional guidance on pipeline in-line inspection.~~

Internal inspection tools shall have capability of detecting corrosion and deformation anomalies viz. dents, gouges, grooves, etc. Instrumented Pigging (Intelligent Pigging) or any other technology that can provide a level of integrity assessment equivalent to In-line Inspection in accordance with provisions of Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipelines) Regulations, 2009 may be employed as Integrity Assessment Method.

5.1.2 Hydro / Pressure Testing of In-service Pipelines

Hydro / Pressure testing is appropriate for integrity assessment when addressing certain threats at the pre-commissioning stage itself at test pressure specified in the Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipelines) Regulations, 20[illegible] Hydro Testing / Pressure testing can also be employed as an integrity assessment tool during service life.

5.1.3 Direct Assessment ~~AND EVALUATION~~

Direct assessment is an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity. ~~Direct assessment methods that include visual Non-Destructive Testing (NDT) examination to reinforce and validate findings from in-line inspection and other incidental findings, like during incidental pipeline exposure, pipeline damages and other maintenance activities may also be employed as an Integrity Assessment tools~~.

External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Cracking Direct Assessment (SCCDA) are the available tools for direct assessment and evaluation.

~~5.3.1~~ External Corrosion Direct Assessment (ECDA) can be used for determining integrity for the external corrosion threat on pipeline segments. ~~The ECDA process has the following four components:~~

~~Paras detailing steps moved down~~

While implementing External Corrosion Direct Assessment if the pipe is exposed, the operator is advised to conduct examinations for threats other than that for external corrosion also (like mechanical and coating damages).

~~5.5.2~~ Internal Corrosion Direct Assessment (ICDA) can be used for determining integrity for the internal corrosion threat on pipeline segments. ~~The ICDA process has the following four components.~~

~~(a) Pre-assessment~~

~~(b) Identifications~~

~~(c) Examinations and evaluations~~

~~(d) Post-assessment~~

~~5.5.3~~ Stress Corrosion Cracking Direct Assessment (SCCDA) can be used for determining integrity for the stress corrosion threat on pipeline segments. ~~The SCCDA process has the following four components.~~

~~a) Pre-assessment~~

~~b) Identification~~

~~c) Examinations and evaluations~~

~~d) Post-assessment~~

Each of these assessments are carried out in four steps as below-

(a) Pre-assessment- incorporating various data gathering, database integration and analysis

(b) ~~Identification~~ Indirect Inspection- using either tools or calculations to flag possible corrosion sites, or calls, based on the evaluation or extrapolation of the database

(c) ~~Examinations and evaluations~~ Direct/Detailed Examination- excavation and examination to confirm corrosion at the identified sites and remediation as provided in Schedule 6 of these regulations.

(d) Post-assessment - to determine ~~if dig call decision are taken on a pipeline segment. However, Call decisions are driven by various tools, technologies, or engineering evaluations, but are highly dependent on the level of experience and expertise utilized.~~ the fitness for service of pipeline, re-assessment interval and effectiveness of Direct Assessment.

5.1.4 Other Integrity Assessment Methodology

Other proven integrity assessment methods for pipeline may exist for use in managing the integrity of pipeline. For the purpose of these regulations, it is acceptable for an operator to use these inspections as an alternative to pressure testing or direct assessment (and where ILI is not feasible due to operational or other constraints)

5.2 MONITORING AND SURVEYS

~~5.2~~ 5.2.1 Cathodic Protection (CP) System Monitoring

Following cathodic protection monitoring methods are available:

(i) Pipe to Soil Potential Survey ~~/ Closed Interval Potential Logging Survey.~~
(ii) Transformer Rectifier Unit / Cathodic Protection Power Supply Module - current and voltage monitoring method
(iii) Closed Interval Potential Logging Survey
(iv) Coating Health Surveys (Current Attenuation Test, Direct Current Voltage Gradient survey and ~~Pearson~~ Alternating Current Voltage Gradient Survey)
(v) Pipeline AC & DC Interference Survey* including survey at Foreign Pipeline Crossings, Power Transmission line crossings / parallelism and other Stray current sources

* It shall be mandatory on all the entities involved to facilitate conduct studies / surveys and take mitigation measures

~~5.6~~ 5.2.2 Thickness assessment and periodic review against baseline values

For all sections of the pipelines above ground, all pipeline skids and pressure vessels, a periodic thickness assessment and comparison with baseline values may be done and employed as Integrity Assessment tool.

The second paragraph moved at the start of schedule 5

~~5.7~~ 5.2.3 Pipeline equipment Health Monitoring

Pipeline equipment such as main line sectionalizing valves, other valves, pig launching and receiving facilities etc. may be checked periodically for their operation.

5.3 Surveillance

Various effective surveillance methods are being used as direct integrity assessment tools. Based upon the experience and resource management, one or multiple tools may be followed by the operator; some of them are detailed as under:

5.3.1 Patrolling / Ground Survey of the Right of User which includes Line Walk for ensuring clear visibility of Right of Way/Right of Use, access to maintenance crew along the Right of Way/Right of Use, valve locations and other pipeline facilities. This also helps to observe surface conditions, leakage, construction activity performed by external agencies, encroachments, washouts and any other factors affecting the safety and operation of the pipeline. Also, patrolling ground survey may be done for maintenance of all pipeline markers, kilometer posts and other specific indication marks along the pipeline. This may also include:

- (i) Night patrolling by Line walkers or alternative security surveillance system where the pipeline location is vulnerable from security point of view
- (ii) Right of Use tracking through satellite imaging methods for critical stretches of natural gas pipeline system
- (iii) Aerial survey of Right of Use at critical and in-accessible stretches e.g. hilly regions and Ghat sections etc.

5.3.2 Integrated Surveillance System for critical stretches :

The above system may use various types of detection systems which may be employed for cross country pipelines based on the system requirements. The general details on such detection system are given below:-

1. Fiber Optics System: This detection system works on seismic vibration principle which may be employed for any kind of terrain and soil and is

useful for pipelines crossings. This system is primarily used for buried pipelines.

2. Ground Sensor System: This detection system also works on seismic vibration principle and may also be used for any kind of terrain and soil. Ground sensor system may be used for buried pipelines as well as above ground pipelines.

3. Radar based detection system: This system works on the principle of micro wave reflection. It is applicable for pipeline terrain where large undulation is restricted. However, this may be useful for any kind of soil and preferably used for above ground pipelines.

4. Fence secure data access system: This system works on the principle of violation of boundary and is useful in installation along the pipeline system. The other use of this system could be for pipeline corridor securing pipeline in very sensitive area where there are attacks by terrorists or otherwise.

5.3.4 Awareness Programme:

Villagers and general public along the right of way shall be made aware of the possible consequences of natural gas leaks by providing a list of Do's and Don'ts. Safety awareness among the administration and local public may be created as per the disaster management plan in accordance with the provisions of Petroleum and Natural Gas Regulatory Board (Codes of Practices for Emergency Response and Disaster Management Plan), Regulations, 2010.

~~5.4 Review of existing pipeline Class Locations:~~ (moved to 6.1.6 C)

~~If class location changes are perceived due to demographic changes along the existing pipelines, population density survey may be carried out to ascertain the changes in class location.~~

~~To address the changes in class location of a pipeline from lower to higher class, the provisions mentioned in Technical Standards and Specifications including Safety Standards /ASME B31.8 shall be considered. The one or multiple following mitigation measures may also be considered till same is mitigated as per Technical Standards and Specifications including Safety Standards /ASME B 31.8 requirements -~~

~~a) Section to be declared as vulnerable and frequency of patrolling to be increased as per new class location.~~
~~b) Intelligent pigging/ Direct Assessment frequencies to be increased.~~
~~c) CP monitoring frequencies to be increased including provision of continuous data/PSP logging at the location.~~

~~d) Corrosion monitoring probes to be installed to monitor the corrosion rate.~~
~~e) Provision of carbon fiber wrapping/ composite sleeves/ concrete slabs~~.

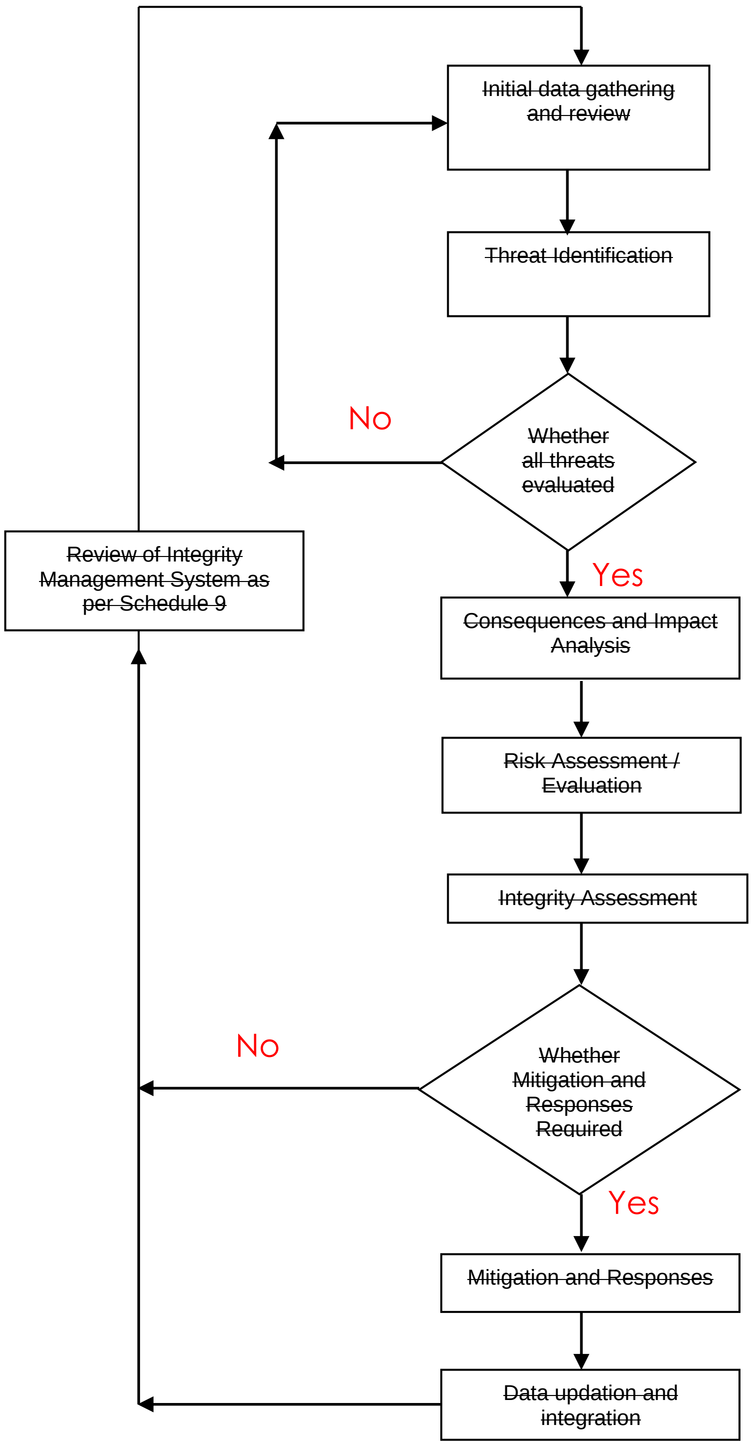
SCHEDULE–6

DESIGNING APPLICABLE INTEGRITY MANAGEMENT SYSTEM FOR THE NATURAL GAS PIPELINE:

All operators of existing and new natural gas transmission and distribution pipelines shall develop an integrity management programme comprising the necessary plans, implementation schedule and assessment of its effectiveness in order to ensure safe and reliable operation of the pipelines. It is recognized that the comprehensive pipeline integrity management programme is based on continuous exercise of extensive data collection, assimilation and analysis. Further, an integrity management programme can be devised on specified methods, procedures and time intervals for assessment and analysis or on the basis of performance of the programme with regard to efficacy of integrity assessment plan, its results and mitigation efforts. For operators implementing an integrity management programme in the absence of base line and performance data, it may become imperative to adopt a prescriptive integrity management programme initially.

6.1 Pipeline integrity management Plan

All natural gas pipelines and associated facilities installed as a part of pipeline shall be covered in pipeline integrity management plan. The cycle of basic processes of integrity management Plan is illustrated in Figure 1 and further detailed hereunder:


~~Initial data gathering and review~~
~~Threat Identification~~
No
~~Whether all threats evaluated~~
Yes
~~Review of Integrity Management System as per Schedule 9~~
~~Consequences and Impact Analysis~~
~~Risk Assessment / Evaluation~~
~~Integrity Assessment~~
No
~~Whether Mitigation and Responses Required~~
Yes
~~Mitigation and Responses~~
~~Data updation and integration~~

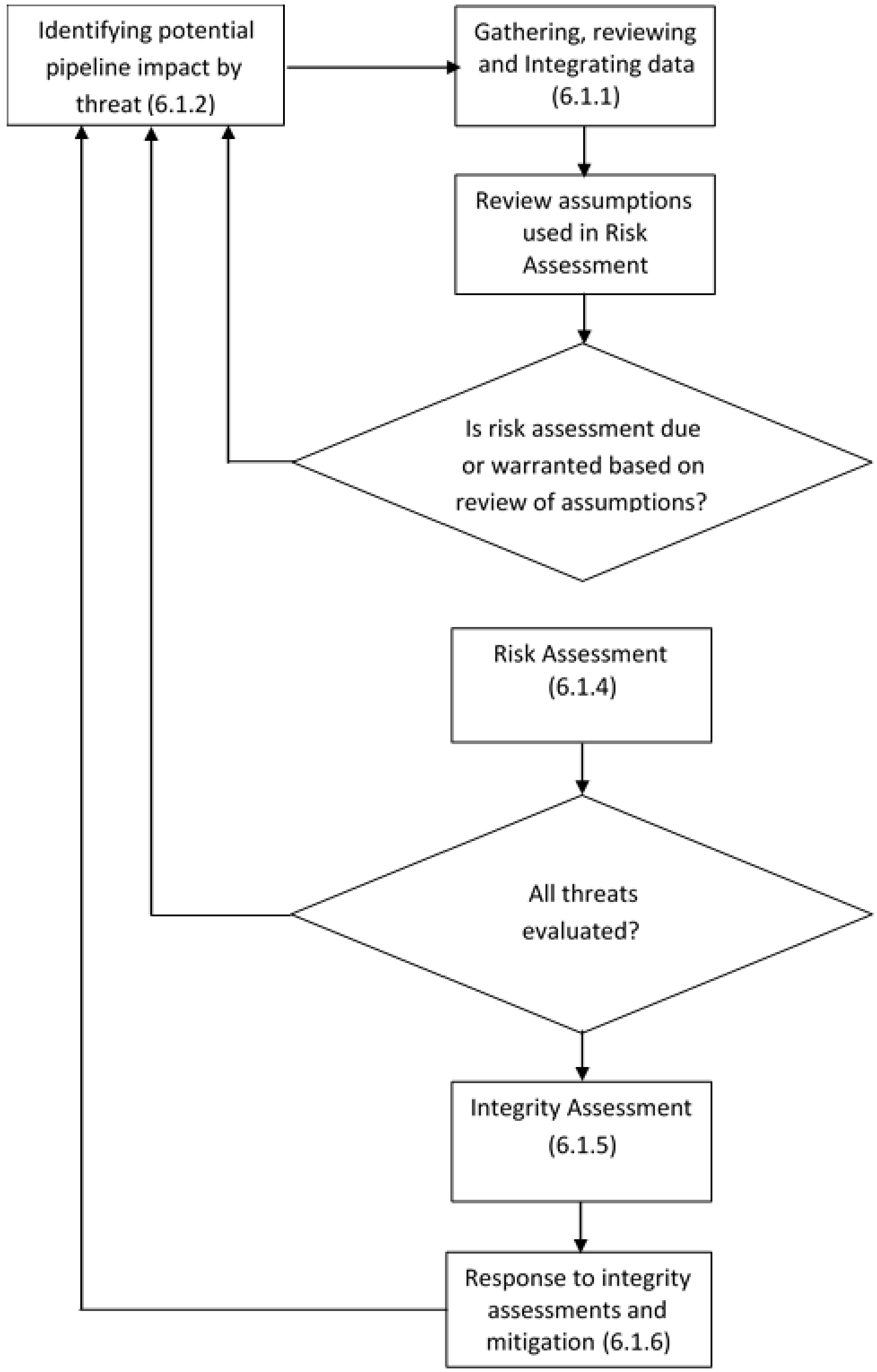


Figure-1: Pipeline Integrity Management Plan - Flow Diagram

6.1.1 Initial Data gathering, review and integration:

Data related to design and engineering, construction, pre-commissioning and commissioning of pipeline assets, operation and maintenance shall be gathered and reviewed along with post-construction operational and integrity assessment data gathered to identify the potential threats along the pipeline system. Operational and integrity assessment data will be continuously updated while performing various activities along the pipeline such as patrolling, aerial surveillance, Cathodic Protection (CP) monitoring, monthly maintenance of equipments etc. and records maintained either hard or soft options.

6.1.2 Threat Identification:

Gas pipeline incident data analyzed and classified by Pipeline Research Committee International (PRCI) represents 22 root causes for threat to pipeline integrity. One of the causes reported by the operator is "unknown". The remaining 21 threats have been classified into three groups based on time dependency and further in to nine categories of related failure types according to their nature and growth characteristic as below:

(I) <u>Time Dependent Threats</u>:

1) ***External Corrosion***
2) ***Internal Corrosion***
    - ***~~Internal corrosion due to off spec. gas* also to be considered~~***
3) ***Stress Corrosion Cracking***

*~~*Refer the Petroleum and Natural Gas Regulatory Board (Access Code for Common Carrier or Contract Carrier Natural gas pipelines) Regulations, 2008.~~*

(II) <u>Stable Threats:</u>

4) ***Manufacturing related defects***
    i. Defective pipe seam
    ii. Defective pipe
5) ***Welding /fabrication related***
    i. Defective pipe girth weld
    ii. Defective fabrication weld
    iii. Wrinkle bend or buckle
    iv. Stripped threads /broken pipe /coupling failure

6) ***Equipment***

i. Gasket O-ring failure
ii. Control/relief equipment malfunction
iii. Seal pump packing failure
iv. Miscellaneous

(III) <u>Time independent Threats:</u>

7) ***<u>Third party /mechanical damage:</u>***

i. Damage inflicted by first, second or third party (instantaneous /immediate failure)
ii. Previously damaged pipe (delayed failure mode)
iii. Vandalism

8) ***Incorrect operational procedure***

9) ***Weather related and outside force:***

i. Weather related
ii. Lightening
iii. Hydro technical: water-related threats including, but not limited to, liquefactions, flooding, channeling, scouring, erosions, floatation, breaches, surges, inundations, tsunamis, ice jams, frost heaves, and avalanches, creek area effects, river meandering, river bed / bank movement
iv. Geotechnical: earth movement threats including, but not limited to, subsidence, extreme surface loads, seismicity, earthquakes, fault movements, mining, and mud and landslides, muddy land effects
v. High wind
~~vi. Heavy Rains or Floods~~
~~vii. Earth Movements~~

~~**Besides the above, certain other threats may be applicable based upon the land pattern.**~~

~~i. Creek area effects~~
~~ii. Muddy land effects~~
~~iii. River bed movements~~

6.1.3 Consequence and Impact Analysis:

Once the hazardous events are identified, the next step in the risk analysis is to analyse their consequences, that is, estimate the magnitude of damage to the public, property and environment of all the identified threats. These consequence may include leak, fire, explosion, gas cloud etc. ~~Consequence estimation can be accomplished by using mathematical models e.g. consequence modelling.~~

~~**Identification of High-consequence area (HCA):** Locations along the pipeline system meeting the criteria for High-Consequence Areas are identified.~~ **Potential Impact Area:** Generally, these are high-population-density areas, difficult-to-evacuate facilities (such as hospitals or schools), and locations where people congregate (such as places of worship, office buildings, or fields). ~~Clause no. 3.2 of ASME B 31.8 S may be referred for detailed information regarding potential impact area.~~

6.1.4 Risk assessment specific to pipeline system

6.1.4.1 Developing a Risk Assessment Approach ~~Model~~: Risk assessment process identifies the location-specific events or conditions, or combination of events and conditions that could lead to loss of pipeline integrity, and provides an understanding of the likelihood and consequences of these events.

The risk assessment has the following objectives:

- Prioritization of pipeline sections/segments for scheduling integrity assessment and mitigation plan
- Assessment of the benefits derived from mitigation actions
- Determination of the most effective mitigation measures for the identified threats
- Assessment of the integrity impact from modified inspection intervals
- Assessment of the use of or need for alternative inspection methodology
- More effective resource allocation

Pipeline sections may be prioritized for integrity assessment based on severity of composite risk due to all threats. The composite risk value for particular pipeline section is product of relative likelihood of failure and consequences altogether due to all applicable threats. Risk priority shall be established for pipeline sections observed with high risk to organize the integrity assessment. The risk may simply be categorized as high, medium, low (or 1, 2, 3) or larger range, to differentiate the priorities among various sections.

Following approaches for risk assessment and prioritization may be adopted as deemed suitable to the Operators:

a) Utilizing the services of Subject Matter Experts (SMEs)
b) Relative Assessment Model
c) Scenario –Based Model
d) Probabilistic Models

The risk assessment models mentioned above have following common features:

(a) They identify potential events or conditions that could threaten system integrity;
(b) They evaluate likelihood of failure and consequences;
(c) They permit risk ranking and identification of specific threats that primarily influence or drive the risk;
(d) They lead to the identification of integrity assessment and/or mitigation option;
(e) They provide for a data feedback loop mechanism;
(f) They provide a structure and continuous updating for risk reassessments

Risk assessment considering the likelihood and consequences through risk assessment approaches may not consider the extent of failure that is leak or rupture. If failure cannot be identified as leak or rupture while assessing the risk through any of the above models, a worst case scenario may be considered.

6.1.4.2 Risk Assessment for the pipeline system:

The risk assessment is continuous and repetitive process. System wide risk assessment shall be carried out ~~at least~~ every year by pipeline operators through any of the methodology mentioned above after incorporating and updating the recently captured data in risk model such as :

- Increase in Operating Pressure, average temperature/dew point of gas, water content in gas beyond acceptable limits.
- Changes in Right of Use conditions like development of encroachments, increase in third party activities/ population density, major washouts.
- Pipeline Leak/rupture history.
- Addition of new /expansion of the existing railway/road/waterway crossings.
- Changes to pipeline cathodic protection levels due to external interference problems.
- Any other issues which may affect the integrity of pipeline.
- The results of previous integrity assessments.

The risk assessment may be performed earlier if any new threat is perceived. The risk assessment process and method shall be reviewed and updated periodically to achieve the objective of pipeline integrity management plan consistently.

The result of risk assessment shall be arranged in descending order for each section for prioritizing the section for conducting integrity assessment after selecting the appropriate integrity assessment method based on most significant threats to particular section.

6.1.5 Integrity Assessment:

A plan shall be developed to address the most significant threats and risks as per previous section and determine appropriate integrity assessment methods to assess the integrity of the pipeline segment. The following methods can be used for Integrity Assessment:

- ~~Hydro~~ Pressure testing ~~before commissioning at test pressure as per T4S standard~~
- Inline inspection (ILI)
- ~~External & Internal Corrosion~~ Direct Assessment (ECDA, ICDA & SCCDA)
- Any other Integrity Assessment methodology
- ~~Various forms of pipeline surveillance and monitoring e.g. patrolling Integrated Surveillance System (ISS) etc~~

Brief description of various Integrity Assessment methods has also been provided in Schedule-5 of these regulations.

Selection of appropriate integrity assessment method shall be based on most significant threats to which particular segment are susceptible. One or more integrity assessment methods can be used depending upon the threats to particular segment of pipeline.

The operator of a pipeline system shall develop a chart of most suited integrity assessment method and assessment interval, prevention and mitigation measures for each threat and risk. The operator shall further develop appropriate specifications and quality control plan for such assessment. After establishing effectiveness of assessment, the interval of assessment may be further modified subject to the requirements under the Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipeline) Regulations, 2009 and other relevant Regulations. A suggestive chart is placed at Appendix –III.

6.1.6 Mitigation and Response (Repair and Prevention)

After the completion of Integrity assessment like inline inspection, ~~and~~ coating health surveys etc., the results shall be evaluated and the necessary repairs and preventive actions shall be undertaken to eliminate the threat to pipeline integrity.

Immediately upon completion of integrity assessment, a comprehensive schedule of repair shall be prepared. All anomalous conditions discovered through the integrity assessment shall be evaluated and classified under the following three categories based on severity of defect. Mitigation action (repair and prevention) shall be undertaken to eliminate an unsafe condition to the integrity of a pipeline or to ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(A) <u>Mitigation through Repair Actions:</u>

At the time of establishing schedules, responses shall be divided into three groups and repair actions shall be as follows:

(a) **Immediate repair conditions:**

Such indication shows that defect is at failure point. This shall include but not limited to any corroded area having -

i) Metal loss equal to or more than 80% of wall thickness.

ii) Predicted failure pressure less than equal to 1.1 times the maximum allowable operating pressure (MAOP) as determined by ASME B31G or equivalent.

iii) Metal loss indication affecting ~~a detected~~ longitudinal seam, if that seam was formed by direct current or low frequency electric resistance welding or by electric flash welding.

iv) Any indication of adverse impact on the pipeline expected to cause immediate or near term leaks or ruptures based on their known or perceived effects on the strength of pipeline which include dents with gouges.

v) Any near term failure indication.

(b) **Scheduled conditions:**

Such indication shows that defect is significant but not at failure point. Following indications shall be examined within one year of discovery:

i) A plain dent that exceeds 6% of nominal pipeline diameter for pipeline operating at or above 30% of Specified Minimum Yield Strength (SMYS).

ii) Mechanical damage with or without concurrent visible indentation of the pipe.

iii) Dent with cracks.

iv) Dent that affect ductile girth or seam welds if the depth is in excess of 2% of the nominal pipe diameter.

v) Dents of any depth that affect non ductile welds.

* For more information on scheduled conditions," *Repair Procedures for Steel Pipelines*" paragraph 851.4 of ASME 31.8 may be referred.

(c) **Monitored conditions:**

Monitored conditions show that defect will not fail before next inspection. Such indications are the least severe and will not require examination and evaluation until next scheduled integrity assessment interval provided that they are not expected to grow to critical level prior to the next scheduled assessment.

(B) Mitigation through Preventive Actions:

The pipeline operator shall develop scheduled programme for monitoring the integrity of the pipeline to prevent from time dependent and independent threats to support the integrity assessment and mitigation plan.

The monitoring scheme and frequency should be decided by the pipeline operator subject to compliance of Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipeline) Regulations, 2009. The few schemes are as follows:

(a) Patrolling of pipelines and associated facilities
(b) Maintenance of Right of User and inspection of Crossings
(c) Pipeline Cleaning,~~/~~ Pigging
(d) Inspection of cathodic protection system
(e) Coating Survey (Closed Potential Logging / Direct Current Voltage Gradient / Pearson/Current Attenuation Test)

(C) Review of existing pipeline Class Locations:

If class location changes are perceived due to demographic changes along the existing pipelines, population density survey may be carried out to ascertain the changes in class location.

~~To address the changes in class location of a pipeline from lower to higher class, the provisions mentioned in Technical Standards and Specifications including Safety Standards /ASME B31.8 shall be considered. The one or multiple following mitigation measures may also be considered till same is mitigated as per Technical Standards and Specifications including Safety Standards /ASME B 31.8 requirements -~~

~~a) Section to be declared as vulnerable and frequency of patrolling to be increased as per new class location.~~
~~b) Intelligent pigging/ Direct Assessment frequencies to be increased.~~
~~c) CP monitoring frequencies to be increased including provision of continuous data/PSP logging at the location.~~
~~d) Corrosion monitoring probes to be installed to monitor the corrosion rate.~~
~~e) Provision of carbon fiber wrapping/ composite sleeves/ concrete slabs~~

The change in Location Class shall be evaluated in accordance with relevant provisions of ASME B31.8 and where action is indicated on account of such change, risk assessment of the impacted pipeline section shall be carried out considering the increase in population density and appropriate mitigation actions shall be taken if required. The mitigation actions should include as many of the following but as a minimum shall include those indicated in the table given underneath the list of actions:

(a) The concerned pipeline section shall be declared as vulnerable and frequency of patrolling to be increased as per new Location Class.

(b) Awareness program among local populace.

(c) Warning Markers shall be installed at lesser interval of distances (minimum every 100 m)

(d) Pipeline cover survey and Mitigation (min every 5 years)

(e) CP monitoring and surveys shall be carried out more rigorously (PSP Off survey – every 6 months)

(f) Frequency of Integrity Assessment shall be increased to a minimum of once in 7 (seven) years or as indicated by risk assessment whichever is more frequent.

(g) Engineering Critical Assessment of the impacted section and mitigation of identified vulnerabilities.

(h) Pipeline barrier protection shall be provided by installing concrete slabs / concrete coating / composite wraps / sleeves etc.

Minimum Required Action after Risk Assessment

Change from lower class to	**Minimum action from list above**
Location Class 2	(a) to (d)
Location Class 3	(a) to (g)
Location Class 4	(a) to (h)

In addition to above, any other actions indicated by risk assessment shall be taken.

6.1.7 Update, integrate and review data:

After the initial integrity assessments are completed, the results shall be maintained in soft, hard or both versions which will be used for future risk and integrity assessments in addition to operational information that is recorded on continuous basis for assessments and implementing risk mitigation plan.

6.2 Performance Evaluation Plan:

Every pipeline operator shall define suitable performance indicators which can be monitored to give a picture of the integrity levels of various aspects of the operator’s pipeline assets. ~~Refer ASME B 31.8S table no 8 and 9 for finalizing~~

~~performance measures and performance matrix respectively.~~ Monitoring of these indicators on a periodic basis against pre-defined targets helps to assess the effectiveness of Integrity Management programme. Performance indicator measures should be selected carefully to ensure that they can reasonably indicate the effectiveness of programme and health of the assets.

An operator can evaluate a system's integrity management programme performance within their own system and also by comparison with other systems on an industry-wide basis.

Such performance evaluation should consider both threat-specific and aggregate improvements. Threat-specific evaluations may apply to a particular area of concern, while overall measures apply to all pipelines under the integrity management programme.

Performance indicator measures may measure either or all of the below as applicable:

(i) Process measures e.g. Number of damages per excavation notification received
(ii) Operational measures e.g. Number of significant In-line Inspection anomalies
(iii) Direct integrity measures e.g. Number of damages per km. of pipeline length

A performance indicator may be either leading or lagging indicator. Lagging measures are reactive in that they provide an indication of past integrity management programme performance. Leading measures are proactive in that they provide an indication of how the plan may be expected to perform.

6.2.1 Performance Measures

Performance measures serve as a tool for evaluating the success of the pipeline Integrity Management System. The performance measures have been developed as a method to gauge the extent to which the pipeline Integrity Management System goals have been met. Performance results demonstrate whether integrity management activities are appropriate or require improvements. The results may be evaluated annually by the pipeline operators, at which time the appropriateness of each performance measure will be assessed. Some of the goals as part of performance measures are illustrated below for reference. The operator may set their own goals depending on priorities and specific problems.

Goals	Performance Measure
To maintain pipeline Pipe-to-Soil Potential (PSP) within acceptable limits	PSP Level

Goals	Performance Measure
Execution of In-line Inspection pigging	As applicable
Leakage and ruptures	Number
Development, Training and Awareness programmes	Number of training and awareness programmes conducted in a year
No Right of Use encroachments	Number of encroachments

In addition to the above performance measures, the pipeline Integrity System Monitoring Report includes the following:

- Patrolling Inspected vs. Planned.
- Key Integrity issues such as encroachments, restoration, constructional deficiencies, mitigation plan and any operational issues.
- The number of Integrity Management System required activities completed.
- The number of defects found requiring repair or mitigation.
- The number of leaks reported.

For performance measures relating to damage events, the following points are documented in the Operator's Damage Prevention Report:

- The number of third party damage events and near misses.
- The number of pipeline hits by third parties due to lack of notification.
- Aerial surveillance and patrolling reports.

6.2.2 Continuous Improvement

The Integrity Management System shall be continuously evaluated and modified to accommodate changes in pipeline design and operation, changes in both the physical and regulatory environment in which the system operates and new operating data or other integrity related information. Continuous evaluation is required to make sure that the programme takes appropriate advantage of improved technology and that the programme remains integrated with the operator's business practices and effectively supports the operator's integrity goals.

Integrity Management System shall be evaluated and reviewed as per the frequency described in Schedule-9 of these regulations. Issues that would typically be reviewed may include, but are not limited to:

- Performance measures.

- Testing and inspection successes and failures.
- New threat identification.
- Root cause analysis of pipeline breakdowns and accidents.
- Process enhancement / changes (Management of Change).
- Recommended changes for the Integrity Management System.
- Additional training requirements necessary to support Integrity Management System.
- Public awareness programme.
- Inspection tool performance (whenever applicable).
- Inspection tool vendor performance.
- Alternative repair methods.
- Staffing for inspections, testing and repairs.
- Past and present assessment results.
- Data integration and risk assessment information.
- Additional preventive and mitigating actions.
- Training needs of O&M personnel.
- Additional items as necessary to aid in the success of the IMP programme.

Based on results of the internal reviews, integrity assessment and mitigation programme shall be improved and documented.

6.3 <u>Communication Plan</u>:

This provides a framework for developing and implementing a written internal and external communication programme for operators of natural gas transmission lines and distribution pipelines. All pipeline operators shall develop and implement a communication plan to disseminate the integrity management efforts undertaken by pipeline operator and also to receive internal and external information or input. This programme must address intended audiences, message content, communication, frequencies and methods and programme evaluation. The information received through external/internal communication should be considered for risk assessment, integrity assessment and mitigation. The communication plan typically comprises, establishment of external and internal communication system as follows:

6.3.1 External Communication:

This should cover the communication plan with external agencies, which are not directly related with operator's business, for propagating information regarding presence of pipeline location, damage preventing actions, company contact information for reporting leakage and informing before carrying out any excavation etc. The various means such as web site, warning boards, pamphlet distribution, street plays etc. can be utilized by operators for this purpose. The following external agencies may be targeted:

(I) Land owner and tenants along the Right of Use

(II) General Public / Public institutions like schools, hospitals etc. near pipeline route

(III) Public officials and statuary bodies other than emergency responders

(IV) Local and regional emergency responders

6.3.2 Internal Communications:

This should cover the dissemination of the information to employees and persons involved in operation and maintenance of pipeline system regarding integrity management programme to understand and comply with the programme objectives and requirements. Such a plan is also expected to fully cover the flow of information and controls in response to emergencies.

6.4 <u>Management of Change:</u>

Pipeline systems and the surrounding environment in which pipelines operate are often dynamic and need changes depending upon operational or any other requirement. Prior to implementation of any changes to pipeline system, a systematic process shall be adopted to ensure that prospective changes (such as design, operation, or maintenance) are evaluated for their potential risk impacts to pipeline integrity including impact on environment. All natural gas pipeline operators shall define a management of change plan in integrity management programme to at least address the following:

(i) Reason for Changes

(ii) Authority to approve changes

(iii) Analysis of implications (threat and risk analysis)

(iv) Documentation

(v) Communication of changes to affected parties

After implementation of changes, they shall be incorporated, as appropriate, into future risk assessment to ensure that the risk assessment process addresses the systems as currently configured, operated, and maintained. The results of the Integrity Management Plan's mitigation activities should be used as feedback for systems and facilities design and operation.

Changes to the pipelines could affect the priorities of the pipeline Integrity Management Plan and the risk mitigation measures employed. Any change in design basis, process or operational issue that can affect the risk rating has to be routed through Management of Change.

6.5 Quality Plan ~~Control~~

All the entities shall prepare and maintain documented procedure and records as per the requirement of this standard which can also be made part of existing Quality Management programme (e.g. ISO-9001~~-2001~~) maintained by the entities. The following activities shall be made part of quality control programme:

- **(i)** Identifying and maintaining the documents required for Integrity management plan, procedures and records. This includes both controlled and uncontrolled documents.
- **(ii)** Defining roles and responsibilities for implementation of programme, documentation etc.
- **(iii)** Reviewing of Integrity Management Plan and implementation of recommendation at predefined interval.
- **(iv)** Training and awareness of persons implementing the Integrity management plan.
- **(v)** Periodic internal Audit of integrity management plan and quality plan.
- **(vi)** Documentation of corrective actions taken or required to be taken to improve the integrity management plan or quality plan.

Rest paragraph moved to Section 9.2

SCHEDULE 7

APPROVAL OF INTEGRITY MANAGEMENT SYSTEM (IMS):

A Natural gas pipeline Integrity Management System is a management plan in the form of a document that explains to operator's employees, customers, regulatory authorities, etc., as to how the operator and its assets are managed, by stating:

- (i) who is responsible for each aspect of the asset and its management;
- (ii) what policies and processes are in place to achieve targets and goals;
- (iii) how they are implemented;
- (iv) how performance is measured and;
- (v) how the whole system is regularly reviewed and audited.

For the first time the approval of the IMS document shall be done by the Board of the entity. While during review to be done every three years, the approval shall be done by CEO / Full time Director of the company and all levels of management shall comply with its contents. Necessary awareness shall also be created within and outside the company regarding benefits to the society for up keeping of the pipeline system for all times to come.

Preparation of the document shall be done in following three stages and six steps:

7.1 MANAGEMENT APPROVAL:

- **Step#1:** Prepared by In-house team or Consultant
- **Step#2**: Checked by In-house team Head or Consultant head
- **Step#3**: Provisionally approved by Head of Operation /Maintenance ~~team~~ of the entity
- **Step#4**: Verification of Conformity of IMS document with the Regulation by Third Party Inspection Agency (TPIA)

~~7.2 ACCEPTANCE BY PETROLEUM AND NATURAL GAS REGULATORY BOARD (PNGRB)~~

- ~~**Step#5**: Acceptance by the Board~~

7.~~3~~ 2 APPROVAL FOR IMPLEMENTATION

- **Step#~~6~~5**: Approval of Integrity Management System document for implementation by the Board of the entity for the first time and approval of subsequent periodic review by CEO or Full-time Director of the entity
- **Step#6:** Approved IMS document along with confirmation from entity of its implementation ~~certificate that Integrity Management System document duly approved as specified at clause no. 7.2 above has been implemented and the certificate along with IMS document~~ shall be submitted to the Board

Note: ~~A certificate regarding the approval of Integrity Management System document duly approved as specified at clause no. 7.1 above shall be submitted to the Board that the Pipeline Integrity Management system is in line with the requirements of the various regulations issued by the Board from time to time and has been approved by the CEO or full time Director of the company.~~

SCHEDULE-8

IMPLEMENTATION SCHEDULE of Integrity Management System:

Sr. No.	Activities	Time Schedule*
1	Compliance with Petroleum and Natural Gas Regulatory Board (Technical Standards and specifications including Safety Standards for Natural gas pipelines) Regulations, 2009	YES/NO confirmation within 1 month from date of notification of these regulations
2	Preparation of Integrity Management System document and approval by Head of Operation team of the entity.	1 year from date of notification of these regulations
3	Conformity of Integrity Management System document with regulation by Third Party Inspection Agency.	3 months from the approval by the Head of Operation/Maintenance~~ team~~ of the entity.
~~4~~	~~Submission of Integrity Management System document to Petroleum and Natural Gas Regulatory Board~~	~~1 month from the conformity of Integrity Management System by Third Party Inspection Agency~~
4~~5~~	Approval for implementation by the ~~entity~~ Board of the entity for the first time and approval of subsequent periodic review by CEO or Full-time Director of the entity	Within 3 months from the conformity assessment by Third Party Inspection Agency (TPIA). ~~acceptance of Integrity Management System document by Petroleum and Natural Gas Regulatory Board~~
5~~6~~	Start of Implementation	Immediately after approval at Sr. No. 4~~5~~ above

6	Submission of Integrity Management System document to Petroleum and Natural Gas Regulatory Board	1 month from the approval as mentioned at Sr. No. 4 above
7	Submission of Compliance Statement to Petroleum and Natural Gas Regulatory Board	Shall be submitted ~~within 1~~ every year to Petroleum and Natural Gas Regulatory Board

<u>Note</u>: Steps for implementation to be followed as described in Schedule-7

*** - For new pipelines, the above shall be complied within one year of date of commissioning**

SCHEDULE-9

REVIEW OF THE INTEGRITY MANAGEMENT SYSTEM

9.1 Periodicity of review of Integrity Management System

Entities ~~shall~~ may review their existing Integrity Management System from time to time but not exceeding an interval of every 3 years and update the same if required in accordance with the provisions of Schedule 7 based on the performance of Integrity Management Program and /or changes if any in the statutory / regulatory requirements. However, changes of dynamic nature such as addition, deletion, modification of assets, key personnel, interfaces with other utilities etc. may not require revision in the IMS and the same can be kept updated periodically by the concern entity ~~every 3 years based upon the:~~

~~(i) Revised Baseline data~~

~~(ii) Critical Inputs from various departments~~

9.2 Integrity Management System Audit

~~Internal~~ Audit~~s~~ of the Pipeline Integrity Management System shall be performed on a regular basis. The purpose of the audits is to ensure compliance with the policies and procedures as outlined in these regulations. Recommendations and corrective actions taken shall be documented and incorporated into the Pipeline Integrity Management System.

~~Internal audits are conducted by the audit group nominated by Head of the Operations Team of the entity at least once in a year. Internal audits aim to ensure that the Integrity Management System's framework is being followed.~~

The following essential items will be focused for any internal and external audit of the entire Integrity Management System:

- IMS document is developed, approved and is valid.
- Activities are performed in accordance with the Integrity Management System.
- Verify if annual performance measures have been evaluated
- All action items or non-conformances are closed in a timely manner.
- The risk criteria used have been reviewed and documented.
- Prevention, mitigation and repair criteria have been established, met and documented.
- ~~Ensure that the Baseline Plan is being updated and followed and that the baseline inspections are carried out.~~

- ~~Verify qualifications of O&M personnel and contractors based on education qualification (Appendix-IV), formal training received through in-house or external programme, demonstrated practical skills, and experience records in the relevant areas. Refer ASME B31Q for guidance.~~

- ~~Ensure adequate documentation is available to support decisions made.~~

- ~~Determine if annual performance measures have been achieved.~~

- ~~A written integrity management policy and programme for all elements.~~

- ~~Written Integrity Management System procedures and task descriptions are up to date and readily available.~~

- ~~Activities are performed in accordance with the Integrity Management System.~~

- ~~A responsible individual has been assigned for each task.~~

- ~~All required activities are documented.~~

- ~~All action items or non-conformances are closed in a timely manner.~~
- ~~The risk criteria used have been reviewed and documented.~~
- ~~Prevention, mitigation and repair criteria have been established, met and documented~~.

9.3 Frequency ~~Review~~ of Internal and External Audit

There shall be a system for ensuring compliance to the provisions of these regulations by conducting following audits during operation phase:

(a) Internal Audit - ~~as per the checklist for natural gas pipelines provided by Petroleum and Natural Gas Regulatory Board shall be carried out by the management of operator~~ Every year.

(b) External Audit ~~(EA)~~ – Every 3 years in-line with the approved IMS by third party empaneled~~, approved~~ by the Board.~~, as per the methodology specified by the Petroleum and Natural Gas Regulatory Board every 3 years.~~

SCHEDULE-10

Adequacy of Manpower positioned at different stage of project

Entity shall have a written plan / philosophy of manning the installations based on activities required for compliance to this regulation. Entity ~~will have to~~ shall address the requirement of manpower for different stages of project, namely: Design, construction, commissioning, operation and maintenance in the above plan.

~~The entity which is preparing Integrity Management System should address the manpower requirement for its present and future operations. The qualification of such manpower shall conform to~~ ~~**Appendix-IV**.~~

APPENDIX-I

REFERENCES

Reference documents of Standard Operation and Maintenance procedures related to Pipeline Integrity may be developed for use of O&M personnel. Some of them are mentioned below for reference:

- Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Natural gas pipelines) Regulations, 2009;
- Petroleum and Natural Gas Regulatory Board (Codes of practices for Emergency Response and Disaster Management Plan) Regulations, 2010;
- ASME B31.8-Gas Transmission and Distribution Piping Systems;
- ASME B31.8S – Managing System Integrity of Gas Pipelines;
- ASME B31 Q- Pipeline Personnel Qualification
- ASME B31G - Manual for Determining Remaining Strength of Corroded Pipelines.
- Gas Research Institute - 00/0189 - A model for sizing high consequence areas associated with natural gas pipelines

APPENDIX-II

CRITICAL ACTIVITIES IMPLEMENTATION SCHEDULE

S/N	CRITICAL ACTIVITY	TIME SCHEDULE
1	Cathodic Protection (CP) Inspection	As per Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for natural gas pipelines) Regulations, 2009
2	Pigging/Intelligent Pigging	
3	Surveillance	
4	Coating Survey	
5	Hydro-testing	
6	GIS Mapping Implementation	2 years from the commissioning of pipeline
7	Leak Detection System Implementation	2 years

APPENDIX-III

SUGGESTIVE CHART FOR SELECTION OF INTEGRITY ASSESSMENT ~~METHOD~~ / MANAGEMENT METHODS* WITH RESPECT TO SPECIFIC THREAT

Threat Group	Threat	Integrity Assessment ~~Method~~ / Management Methods*	~~Assessment interval~~ Interval
(A)Time-Dependent			
	External Corrosion	Inline inspection / External Corrosion Direct Assessment (ECDA)/ Pressure Testing / Any other Integrity Assessment Methodology	Max.10 year**
	Internal Corrosion	Inline inspection / Internal Corrosion Direct Assessment (ICDA) / Pressure Testing / Any other Integrity Assessment Methodology	Max.10 year**
	Stress Corrosion Cracking	Inline inspection / Stress Corrosion Cracking Direct Assessment (SCCDA) / Pressure Testing / Any other Integrity Assessment Methodology	Max.10 year**
(B) Stable			
a) Manufacturing related defects	Defective Pipe Seam	~~Hydro-test (Post Construction),~~ Inline inspection / Pressure Testing / Any other Integrity Assessment Methodology	Before commissioning or as and when required
	Defective Pipe		
b) Welding / Fabrication related	Defective Pipe Girth Weld		
	Defective fabrication Weld		
	Wrinkle bend or buckle	Caliper Pigging / Electronic Gauging Pigging (EGP)	
	Stripped threads/broken pipe	Visual Examination / Gas Leakage Survey	
c) Equipment	Gasket / O-ring Failure	Visual Examination / Gas Leakage Survey	
	Control / Relief equipment malfunction	Visual Examination / Gas Leakage Survey	
	Seal pump packing failure	Visual Examination / Gas Leakage Survey	

(C)Time-Independent			
a) Third Party / Mechanical Damage	Damage inflicted by first, second, or third parties (Instantaneous / Immediate failure)	Public Education (See Communication Plan & preventive actions), Patrolling, ROW Maintenance, External Protection	Monthly / Quarterly
	Previously damaged pipe (delayed failure mode)	Above + Leakage Survey, Rehabilitation	
	Vandalism	All above	
b)Incorrect Operations	Incorrect Operational procedure	Compliance Audits	
c) Weather Related and Outside Forces	Weather related	Leakage survey, Surveillance	As and when required
	Lightning	Inspection of Surge diverters	
	Heavy rains or floods	~~Anti-buoyancy~~ Inspection, Surveillance	
	Earth Movements	Strain monitoring, Leakage survey.	
	Creek Area Effects	Surveillance, ~~Pipe to Soil Potential surveys near creek,~~ Leakage survey, ~~Anti-Buoyancy~~ Inspection, ~~Integrated Surveillance System~~	As and when required
	Muddy/Marshy area effects	Surveillance, ~~Pipe to Soil Potential surveys,~~ Leakage survey, Cathodic Protection monitoring~~, Integrated Surveillance System~~	As and when required
	River Bed Movements	Surveillance, ~~Pipe to Soil Potential surveys,~~ Leakage survey, ~~Cathodic Protection monitoring, Anti-Buoyancy~~ Inspection~~, Integrated Surveillance System~~	As and when required

*** Some of the important Integrity Assessment ~~Methods~~ / Management Methods have been ~~briefed~~ mentioned in Schedule-5 of these regulations.**

**** Inline inspection frequency to be as per Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for natural gas pipelines) Regulations, 2009.**

~~APPENDIX-IV~~

~~Minimum Qualification and Experience for Field Personnel in Project Phase as well as O&M Stage~~

~~Discipline~~	~~Tier-I~~	~~Tier-II~~	~~Tier-III~~
		~~Supervisor Level~~	~~Operator Level~~
~~Mechanical~~	~~Degree In Mechanical Engineering~~	~~Diploma In Mechanical Engineering + at least 1 year of Experience~~	~~ITI with at least 1 year experience in the relevant field of operation~~
~~Metallurgical~~	~~Degree In Metallurgical Engineering~~	~~Diploma In Metallurgical Engineering + at least 1 year of Experience in Pipeline corrosion control~~	~~ITI with at least 1 year experience in the relevant field of operation~~
~~Instrumentation & Control~~	~~Degree In I&C / Electronics Engineering~~	~~Diploma In I&C / Electronics + at least 1 year of Experience~~	~~ITI with at least 1 year experience in the relevant field of operation~~
~~Electronics & Communication~~	~~Degree In Electronics or Communication Engineering~~	~~Diploma In Electronics or Communication Engineering + at least 1 year of Experience in SCADA~~	~~ITI with at least 1 year experience in the relevant field of operation~~
~~Electrical~~	~~Degree In Electrical Engineering~~	~~Diploma In Electrical Engineering+ at least 1 year of Experience~~	~~ITI with at least 1 year experience in the relevant field of operation~~
~~Fire & Safety~~	~~Equivalent Degree In F&S Engineering~~	~~Diploma In F&S Engineering / at least 1 year of Experience~~	~~Fireman course passed and proficient in operation of fire water pumps and fire tenders with heavy vehicles driving license / at least 1 year experience in the relevant field of operation~~
~~Civil~~	~~Degree In Civil Engineering~~	~~Diploma In Civil Engineering+ at least 1 year of Experience~~	~~ITI with at least 1 year experience in the relevant field of operation~~

~~**Note:** Each Natural gas pipeline shall have SME (Subject Matter Expert) having qualification in any of the discipline mentioned above with minimum 5 year of relevant experience.~~