NOTIFICATION

New Delhi, the............

PETROLEUM AND NATURAL GAS REGULATORY BOARD

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 Petroleum and Petroleum products Pipelines) Regulations, 2014.

   (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) “authorized person” means a competent person who is assigned by the owner or operator to carry out a specific job based on his competency level as laid down by the Board under regulations;

   (c) “Integrated electronic surveillance system” ("IESS") means the pipeline surveillance for third party activities along ROU through electronic means. This may use optical fiber cable, microwaves, and satellite as communication systems and could integrate SCADA’s data;

   (d) intermediate pump station” means the installation located at any place between starting point and the terminal point having pumps to enhance the pressure of the fluid to achieve desired flow rate;
(e) “originating pump station” means facilities installed at the start of the pipeline system for developing required fluid pressure so as to achieve desired flow rates in the pipeline system;

(f) petroleum and petroleum products pipeline” means the pipelines as defined under Petroleum and Natural Gas Regulatory Board (Authorizing entities to Lay, Build, Operate or Expand Petroleum and Petroleum Product Pipelines) Regulations, 2010:

(g) “terminal station” means a facility to receive products at the end of the pipeline and this may include the tankage for storage of petroleum and petroleum products;

(h) “operator” means an entity that operates Petroleum and Petroleum products Pipelines with the authorization of the Board;

(i) “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.

(j) “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.


(m) “Right of Use (RoU) or Right of Way (RoW)” means the area or portion of land with which the pipeline operator or owner has acquired the right through the relevant Statutory Acts or in accordance with the agreement with the land owner or agency having jurisdiction over the land to lay and operate the Petroleum and Petroleum product Pipelines;

(n) “Subject Matter Expert (SME)” means an individual who possesses knowledge and experience in the process or discipline they
represent as per ASME B 31 Q”.

(2) Words and expressions used and not defined in these regulations, but defined in the Act or in the rules or regulations made there under, 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 authorized by the Central Government and the authorization accepted by the Board under Regulation 17 (1) of the PNGRB (Authorizing Entities to Lay, Build, Operate or Expand Petroleum and Petroleum product Pipelines) Regulations, 2010 or authorised by the Board to lay, build, operate or expand petroleum & petroleum product pipeline in conformity with relevant regulations notified in this regard by the Board and shall also include dedicated pipelines. The principles and procedures contained in these regulations are applicable to all the pipeline networks – operating or under construction.

4. Scope

These regulations shall cover all the existing and new petroleum & petroleum product pipelines. This includes the associated facilities required for transportation for petroleum & petroleum product through pipelines i.e. storage facilities, delivery stations / terminals, intermediate pigging facilities, pumping stations etc.

For crude pipeline, black oil pipelines and offshore pipelines, schedule – 11, schedule – 12 and schedule -13 respectively may be referred.

The materials and specifications followed shall be in accordance with Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for petroleum & petroleum product pipeline) Regulations as and when notified by the Board.

5. Objective

These Regulations outline the basic features and requirements for developing and implementing an effective and efficient integrity management plan for Petroleum and Petroleum product Pipeline system.
i) Evaluate the risk associated with petroleum & petroleum product pipeline and effectively allocate resources for prevention, detection and mitigation activities;

ii) Improve the safety of petroleum & petroleum product pipeline so as to protect the personnel, property, public and environment;

iii) Have streamlined and effective operations to minimize the probability of pipeline failure.

6. **Integrity Management System**

The development and implementation of Integrity Management System for the petroleum & petroleum product pipeline shall be as described in SCHEDULE-1 to SCHEDULE-9 of these regulations.

7. **Default and consequences**

   (1) There shall be a system for ensuring compliance to the provisions of these regulations through implementation schedule as described in these regulations at Schedule-8 and Schedule-9 in conjunction to Appendix-II.

   (2) In case of any shortfall in achieving the implementation of Integrity Management System as specified in these Regulations, the entities are liable to face the following consequences:

   (i) The entity is 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(s) shall submit a mitigation plan 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 PNGRB Act, 2006 shall apply;

   (ii) In case the entity fails to implement the approved IMS, 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 statutes**

   It shall be necessary to comply with all statutory rules, regulations and Acts in force as applicable and requisite approvals shall be obtained from
the relevant competent authorities for the Petroleum and Petroleum products Pipelines.

9. Miscellaneous

(1) Through these regulations the uniform application of system integrity is to be ensured for all petroleum & petroleum product pipelines;

(2) Entity operating and maintaining Petroleum and Petroleum product Pipeline shall have the qualified manpower as per three tier structure as indicated in Appendix - IV;

(3) These regulations either on suo-motu basis or on the recommendation of concerned sub-group of petroleum & petroleum product pipelines shall be reviewed by the PNGRB;

(4) **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.
**OBJECTIVE**

The objective of pipeline Integrity Management System is to maintain integrity of petroleum & petroleum products pipelines at all times to ensure public safety, protect environment and ensure availability of pipeline to transport petroleum & petroleum product 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 IMS will enable the transporter to select and identify system for implementation such that the IMS will be uniform for all petroleum & petroleum products pipelines entities within the country.

An effective IMS shall be:

- Ensuring the quality of petroleum & petroleum products pipelines integrity in all areas which have potential for adverse consequences;
- Promoting a more rigorous and systematic management of petroleum & petroleum products pipelines integrity and mitigate the risk;
- Increasing the general confidence of the public in the operation of petroleum & petroleum products pipelines;
- Optimizing the life of the petroleum & petroleum products pipelines with the inbuilt incident investigation and data collection including review by the entity.
INTRODUCTIONS TO THE INTEGRITY MANAGEMENT SYSTEM (IMS)

2.1 Every petroleum & petroleum products pipelines operator’s primary focus is on operation and maintenance of petroleum & petroleum products pipelines 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 provides 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 essentially comprises of the following elements:

- **Integrity Management Plan (IMP):** This encompasses collection and validation of data, assessment of spectrum of risks, risk ranking, assessment of integrity w.r.t. 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) in to integrity management plan to update the integrity management plan.

- **Quality Control:** This is the process to establish the requirements of quality in execution of the processes defined in the integrity management plan.

These elements are further detailed in Schedule-6.
SCHEDULE - 3

DESCRIPTION OF PETROLEUM AND PETROLEUM PRODUCTS PIPELINES SYSTEM

3.1 **PHYSICAL DESCRIPTION:** Description of Pipeline Systems (each pipeline system to have a specific description under this head). It should include Description of design, construction, etc., for

3.1.1 Steel pipeline networks
3.1.2 Storage facilities/tanks-atmospheric/low pressure/high pressure
3.1.3 Main line pumps
3.1.4 Valves
3.1.5 Delivery stations/terminals
3.1.6 Control room / MCS
3.1.7 Instrumentation & electrical structure
3.1.8 System monitoring
3.1.9 Safety
3.1.10 Management

3.2 **OTHER DESCRIPTION:**

3.2.1 Legal and Statutory requirement;
3.2.2 Interfaces with Other Operators’ Facilities or Pipelines;
3.2.3 Life cycle of the components starting with the pipeline system, commissioning date;
3.2.4 Modification carried out in the system;
3.2.5 Inspection update;
3.2.6 Incident, including product leak or pilferage details, etc.;
3.2.7 Information on Documentation Relating to design, construction, operations, maintenance, etc.;
3.2.8 Pipeline Geometry, Ground Movement - Control, Mitigation and Monitoring;
3.2.9 Statement of compliance with Technical Standards and Specifications including Safety Standards for such Pipelines and Associated Laws.
SCEDULE-4
SELECTION OF APPROPRIATE INTEGRITY MANAGEMENT SYSTEM

4.1 The Integrity Management System was introduced by the Department of Transportation, USA way-back in year 1970. This resulted in to the development of Integrity document by API Standard 1160, Managing System Integrity for Hazardous Liquid Pipelines. In Indian context, commercial use of petroleum and petroleum product pipelines started in late eighties with the commissioning of Guwahati-Barauni petroleum and petroleum product pipeline.

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

4.3 Though subsequent schedule in these Regulations apply to both prescriptive and performance based type of IMS, present regulations mainly focus on prescriptive aspects in absence of adequate historical IMS data.

4.4 A prescriptive type of IMS 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 IMP, Management of Change pertaining to technical aspects. Based on the development of petroleum and petroleum product pipeline industry in India till date the preparation of Prescriptive type IMS has been considered for implementation to all petroleum and petroleum product pipelines in India. Further, as the petroleum and petroleum product pipeline industry matures and gathers sufficient records or data as per the requirements prescribed in PNGRB (Technical Standards for petroleum and petroleum products pipelines) Regulations, as and when notified by the Board for recommending a Performance Based Integrity Management System for petroleum and petroleum product pipeline.
**Integrity Assessment Tools**

Some of the tools for Integrity assessment are provided below. The operator should use as many tools necessary to achieve the IMS for petroleum and petroleum product pipeline. It may be noted that the baseline data for specific measurement should be available with the operator as a ready-reckoner:

### 5.1 In-Line Inspection

In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize indications, such as metal loss or deformation, as well as external and internal corrosion in a pipeline. Internal inspection tool or tools capable of detecting corrosion and deformation anomalies viz. dents, gouges, grooves etc. Instrumented (Intelligent Pigging) or any other technology that can provide a level of integrity assessment equivalent to Inline Inspection or direct assessment in accordance with provisions of relevant standards or regulations issued by the Petroleum & Natural Gas Regulatory Board. API Standard 1160, Managing System Integrity for Hazardous Liquid Pipelines, provides additional guidance on pipeline in-line inspection.

In addition the following shall be carried out:

a. Observing dampness of the area and smell of oil product during daily line walking.

b. Pressure loss in the segment during pipeline operation through SCADA monitoring system.

c. Feasibility of placing sensors for detecting any oil leak / vapour / gas leaks in a confined area such as Ports, Jetties, Process Plants, wherever possible particularly for old pipelines which has a proven track record measured through online corrosion monitoring system for > 10 mil loss).

### 5.2 CP MONITORING

Below table gives various methods for CP monitoring and its frequency for implementation:

<table>
<thead>
<tr>
<th>Sr. No.</th>
<th>Cathodic protection monitoring methods.</th>
<th>Time period Frequency for implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>PSP Survey</td>
<td>Once in three month</td>
</tr>
<tr>
<td>2</td>
<td>Diode Bonding Station</td>
<td>Once in three month</td>
</tr>
</tbody>
</table>
5.3 SURVEILLANCE:
The following surveillance method shall be implemented by the entity:

I. Patrolling Ground Survey
Each operating entity shall maintain a periodic pipelines patrol programme. The Patrolling shall be carried out as per the following minimum intervals. And the IMS document should include the following:

(a) The right of way shall be inspected and maintained once in a year to ensure clear visibility of ROW/ROU, access to maintenance crew along the RoW/RoU, valve locations and other pipeline facilities. All pipeline markers/kilometre posts and other signs/specific indication marks shall be maintained.

(b) Patrolling to observe surface conditions, leakage, construction activity other than performed by the pipeline owning entity, encroachments, washouts and any other factors affecting the safety and operation of the pipeline, in any of the following methods.

II. Line Walk by the representative of the entity shall be carried out at least four times in a year (on a quarterly basis) for entire length of pipeline.

III. Identify the vulnerable locations from pilferage point of view and implement nigh patrolling by Line walkers or alternative security surveillance system at such locations.

The following alternative surveillance methods may also be considered for implementation

<table>
<thead>
<tr>
<th></th>
<th>Method</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>TR / CPPSM- CP stations</td>
<td>Once in a month in the field, if not online, Once in a three months if online</td>
</tr>
<tr>
<td>4</td>
<td>Coating Health Surveys (CPL &amp; DCVG)</td>
<td>Immediate after commissioning and once in a five year.</td>
</tr>
<tr>
<td>5</td>
<td>Foreign Pipeline interference Survey</td>
<td>Immediate after commissioning. Based on the CP data of such interference survey minimum once in 5 years.</td>
</tr>
<tr>
<td>6</td>
<td>Anode Bed resistance</td>
<td>Once in a year</td>
</tr>
<tr>
<td>7</td>
<td>Anode Bed current dissipation</td>
<td>Once in a three months</td>
</tr>
<tr>
<td>8</td>
<td>Resistance of each Galvanic Anodes installed for earthing at HT line crossings</td>
<td>Once in a year</td>
</tr>
</tbody>
</table>
IV. Aerial Survey of RoU wherever possible shall be carried out once in 5 years, at critical & in inaccessible stretches (hilly & ghat section) once in a year.

V. RoU Tracking through satellite imaging method for critical stretches may be carried out preferably once in a month or fortnightly basis if possible, to track for ground profile disturbance.

VI. **Integrated Electronic surveillance system IESS** may various types of detection system which may be employed for cross country pipelines based on the system requirement. The general details on such detection system are given below:

1. Fiber Optics System: The detection system works on seismic vibration principle which may be employed for any kind of terrain and soil and is useful for pipeline crossings. This system is primarily used for buried pipelines.

2. Ground Censor System: This detection system also works on seismic vibration principle and may also be used for any kind of terrain and soil. Ground censor 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 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 is attacks by terrorists or otherwise.

VII. **Awareness Programs**: Villagers and general public along the right of way are made aware of the possible consequence of hydrocarbon leaks with providing a list of Do’s and Don’ts. This shall be included as a part of regular audit. Awareness with the administration and local public can also be obtained by conducting Offsite Disaster Management Plan on the country side pipeline in line with the PNGRB (Codes of Practices for Emergency Response and Disaster Management Plan), Regulations, 2010 which would highlight the Safety awareness among the Local Public and District Administration.

5.4 Pigging

The frequency of de-scaling and cleaning of pipelines transporting petroleum and petroleum products shall be as under:

   i. Non ATF Petroleum Product Pipelines - Once in six months.
   ii. LPG Pipelines - Once in a year.
iii. ATF pipelines also carrying other petroleum products - Once in three months.
iv. Dedicated ATF Pipelines: Once in a year

Record of quantity and quality of deposits (pig residue) collected after descaling shall be examined to monitor condition of the Pipeline. Depending upon the outcome of the chemical analysis and review, pigging frequency may be increased.

5.5 Instrumented / Intelligent Pigging

Instrumented (Intelligent pigging survey, IPS) shall be carried out in line with the Technical Standard and Specifications including Safety Standards as and when notified by the Petroleum and Natural gas Regulatory Board for piggable pipelines and as amended from time to time.

5.6. Supervisory Control and Data Acquisition (SCADA)

SCADA should comprise of communication system and comprising of integral modules, IESS, leak detection etc. and should be in operating condition at all times.

5.7. Pressure testing

Pressure testing is appropriate for integrity assessment when addressing certain threats, at the pre-commissioning stage itself.

5.8. Direct assessment and evaluation

Direct Assessment is a structured improvement process through which an operator can assess the integrity of a pipeline. Direct Assessment uses a combination of corrosion technologies, accompanied by physical inspections, to assess the integrity of pipeline with respect to external corrosion (EC), internal corrosion (IC) and stress corrosion cracking (SCC).

Direct assessment can be used as a primary assessment method or as a supplement to other assessment methods.

External Corrosion Direct Assessment (ECDA) process has the following components:

(a) Pre-assessment- incorporating various data gathering, database integration, and analysis
(b) Identification - 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 - excavation and direct assessment to confirm corrosion at the identified sites, and remediation as defined in regulation,
(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.

While implementing ECDA and when the pipe is exposed, the company is advised to conduct examinations for threats other than that for external corrosion also (like mechanical and coating damages).

**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) Indirect Assessment  
(c) Examinations and evaluations  
(d) Post-assessment

### 5.9 Thickness assessment and periodic review against baseline values

Periodic thickness assessment for all pipeline skids and pressure vessels and comparison to baseline values shall be done once every four years.

Such other methods for integrity assessment may be also adopted by the pipeline company as it thinks fit, apart from the above mentioned ones.

5.10 Preventive maintenance based on predictive maintenance for all rotary equipments like pumps, CCVT and also for static equipments such as filter, separator, heaters including storage tanks shall be carried out based on

i. Vibratory signature  
ii. Thickness Survey  
iii. Lube Oil analysis / debris analysis  
iv. Heat analysis for electric cable

Minimum safety of storage tank shall be full containment.
All operators of existing and new petroleum and petroleum product pipelines shall develop an integrity management Program 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 program is based on continuous exercise of extensive data collection, assimilation and analysis. Further, an integrity management Program can be devised on specified methods, procedures and time intervals for assessments and analyses 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 Program in the absence of base line and performance data, it may become imperative to adopt a prescriptive integrity management program initially.

6.1 Pipeline integrity management Plan

All petroleum and petroleum product 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 (Fig -1) and further detailed hereunder:
6.1.1 Initial Data gathering, review and integration

One of the most critical parts of the pipeline integrity program or risk management is the collection of accurate information on the present.
condition of the pipeline collected by excavations or various survey techniques. One method for collecting accurate data has been to inspect the pipeline via a “smart pig” or In-Line Inspection Tool (ILIT). The data so collected shall be analysed for corrective actions.

In-line inspection tools were developed for the purpose of locating and monitoring corrosion on both internal and external surfaces of the pipeline. The survey tool is a self-contained system that performs a full circumferential corrosion inspection from the pig launcher to the pig receiver.

The advantage of these inline tools is that they offer the operator “direct integrity information” previously only available through hydrostatic proof testing or digs. Typical ILI output data includes: anomaly location - both linearly along the pipe axis, as a function of internal or external position, and percentage wall loss.

The following records shall be maintained by the pipeline operators for all new pipelines constructed after the issue of these recommended practice.

i. Design & Engineering documents
ii. Construction inspection reports
iii. Material certification, performance and functional reports.
iv. A complete pipe book
v. Pressure test records including location of leaks or failures, if any, and description of repair undertaken
vi. Record of Calliper survey, if carried out
vii. Complete asset of each location with identification
viii. As-built drawings including pipeline route maps, alignment sheets, crossings drawings, Piping and Instrumentation Diagrams, station layouts, piping isometric, earthing grid, single line diagrams, instrument and cable layouts, loop diagrams, etc.
ix. Equipment manuals supplied by manufacturers
x. Approved Vendor drawings
xi. NDT records of welds
xii. Cleaning and swabbing report
xiii. Geometric survey reports/EGP Survey to be done once in 3 years and repairs, if any, carried out.
xiv. Statutory Clearances
xv. Calibration records of instruments, measuring, metering and test
equipment.
xvi. Pre-commissioning Audit compliance report
xvii. Details of ROW / Rou Owners, pending court cases pertaining to acquisition of ROW / RoU.
xviii. Operation daily logs
xix. Pipeline patrolling records
xx. Encroachment Records
xxi. Pearson survey records/Continuous Interval Potential Loging (CIPL to be done once in 5 years) or Continuous Potential logging (CPL) or / Direct Current Voltage Gradient (DCVG), or Current Attenuation Test (CAT) surveys etc.
xxii. Pipeline pigging records
a) Scraper pigging through foam pig or four cup pig once in six months.
b) Intelligent pigging as per the provisions of relevant standards.
xxiii. Records and maps showing the location of CP facilities and piping.
xxiv. CP monitoring report, test and survey reports.
xxv. Leak, burst & repair and test records
xxvi. Records pertaining to inspections, such as external or internal line conditions
xxvii. Near miss, minor and major incidents
xxviii. Integrity assessment data
xxix. Various pilferages and chainages (location village reference), date of event (on pilferage carried out), precautionary measures/steps, taken
xxx. Soil resistivity reading or soil sample test on ROU after every 5 years, or any major change in the ground profile due to industrial effluents or new water bodies.

6.1.2 Threats Identification: 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 grouped into three groups based on time dependency and further into nine categories of related failure types according to their nature and growth characteristic as below:

(I) **Time Dependent Threats:**

1) **External Corrosion**
2) **Internal Corrosion**

3) **Stress Corrosion Cracking**

**Stable Threats:**

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

**Time independent Threats:**

7) **Third party /mechanical damage:**
   - i. Damage inflicted by first, second or third party (instantaneous /immediate failure)
   - ii. Previously damaged pipe (delayed failure mode)
   - iii. Vandalism
   - iv. Encroachment

8) **Incorrect operational procedure**

9) **Weather related and outside force:**
   - i. Weather related
   - ii. Lightening
   - iii. Heavy Rains or Floods
   - iv. 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
iv. crossing of various utilities: proper safety guideline to be stipulated with documentation

**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, i.e., estimate the magnitude of damage to the public, property and environment of all the identified threats. These consequences may include:

(i) Leak  
(ii) Mass release/Continuous release  
(iii) Flash fire/Jet fire  
(iv) Explosion  
(v) UVCE (unconfined vapour cloud explosion)  
(vi) CVCE (confined vapour cloud explosion)  
(vii) Gas cloud  
(viii) Fireball  
(ix) Pool fire  
(x) Tank fire

Consequence estimation can be accomplished by using mathematical models (consequence modelling), which can be at various levels of detail and sophistication.

**Identification of High-consequence area (HCA)**- Locations along the pipeline system meeting the criteria for High-Consequence Areas are identified. Generally, these are high-population-density areas, difficult-to-evacuate facilities (such as hospitals or schools), and locations where people congregate (such as churches, office buildings, or fields).

**6.1.4 Risk assessment specific to pipeline system.**

**6.1.4.1 Risk Management and Risk Assessment**

Risk management is the overall process by which management decides what actions to take, if any, to control or reduce existing or anticipated risks. Risk management involves the systematic application of management policies, procedures, resources, and practices to the tasks of assessing, analyzing, and controlling risk.

The goal of a good risk management system is to protect employees from safety and health point of view, the general public, the environment, and company assets. Risk assessment is only one component within the overall process of risk management.
Traditional pipeline risk management has been based on regulatory code compliance issues as it relates to renewing or replacing corrosion damaged areas, maintaining corrosion prevention potentials, third party protective measures (i.e., ground cover depth, signage), or population encroachment issues.

### 6.1.4.2 Developing a Risk Assessment Model

An effective risk model must consider all aspects related to pipeline degradation and failure. A comprehensive Pipeline Integrity/Risk Assessment process includes, as a minimum, the following components:

(a) Identification of hazards – These hazards are based on experience, industry knowledge, or code compliance issues etc.

(b) Develop a series of relationships (i.e., algorithm) by which to assess or rank the risk significance of each hazard. The algorithm needs to be tempered with the beliefs, operational and maintenance practices of the pipeline operator.

(c) Establishing risk reduction objectives and goals.

(d) Develop & implement investigative programs which gather data about each hazard.

(e) Calculating the relative risks along each pipeline, and prepare a risk matrix – this will ultimately be used to confirm if the risk is manageable or unmanageable.

(f) Evaluating risk minimization projects that offer the desired level of risk while maximizing the cost/benefit ratios of potential projects.

(g) Modify pipeline-operating practices to ensure that risk factors are reduced or eliminated.

(h) Monitor systems, which have been introduced, to ensure that the new operating practices are functional.

### 6.1.3 INTEGRITY ASSESSMENT

A plan shall be developed to address the most significant threats/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 testing before commissioning and subsequently during operational phase, at test pressure as per PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum product Pipeline) Regulations as and when notified
- Inline inspection (ILI)
- External & Internal Corrosion Direct Assessment (ECDA/ICDA)
Various forms of pipeline surveillance and monitoring e.g. patrolling, Integrated Electronic Surveillance System (IESS) etc.

Brief description of various Integrity Assessment methods has been also 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 method 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 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 PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum product Pipeline) Regulations, as and when notified and other relevant Regulations. A suggestive chart is placed at Appendix –III.

6.1.4 MITIGATION & RESPONSES (Repair and Prevention)

After the completion of integrity assessment 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 ensured that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment.

(A) Mitigation through Repair Actions:

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 weld 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 SMYS

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

iii) Dent with cracks

iv) Dent that affects 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” para 851.4 of ASME 31.8 may be referred.

(c) **Monitored conditions:** Monitored indications shows 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:**

Some of the mitigation actions are listed below:

- Actions for increasing the adequacy levels of CP protection, like increasing CP current levels, installation of additional capacity etc.
- Replacement / repair of pipe sections based on analysis outcomes. This has to be based on the applicable PNGRB standards
• Consultation with equipment suppliers for deciding course of actions

Liquids – High Consequential Areas Repair Conditions

<table>
<thead>
<tr>
<th></th>
<th>60 Days</th>
<th>120 Days</th>
<th>180 Days</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Metal Loss</strong> &gt; 80%</td>
<td><strong>Dent</strong> top of pipe &gt; 6%</td>
<td><strong>Dent</strong> &gt; 2% that affects pipe curvature at girth or seam weld</td>
</tr>
<tr>
<td></td>
<td><strong>Metal Loss</strong> predicted burst pressure &lt; MOP</td>
<td><strong>Dent</strong> top of pipe &gt; 3% (or &gt; 0.25” if pipe diameter &lt; 12”)</td>
<td><strong>Dent</strong> top of pipe &gt; 2% (or &gt; 0.25” if pipe diameter &lt; 12”)</td>
</tr>
<tr>
<td></td>
<td><strong>Dent</strong> top of pipe with metal loss, crack stress riser</td>
<td><strong>Dent</strong> bottom of pipe with metal loss, crack, stress riser</td>
<td><strong>Dent</strong> bottom of pipe &gt; 6%</td>
</tr>
<tr>
<td></td>
<td><strong>Metal Loss</strong> &gt; 50% affecting girth weld or at pipeline crossing</td>
<td><strong>Metal loss</strong> calculated MAOP &lt; MOP</td>
<td><strong>Metal loss</strong> &gt; 50% affecting girth weld or at pipeline crossing</td>
</tr>
<tr>
<td></td>
<td><strong>Crack</strong></td>
<td><strong>Metal loss</strong> area of general corrosion &gt; 50%</td>
<td><strong>Crack</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Corrosion along seam weld</strong></td>
<td><strong>Metal loss</strong> &gt; 50%</td>
<td><strong>Corrosion along seam weld</strong></td>
</tr>
<tr>
<td></td>
<td><strong>Gouge</strong> &gt; 12.5%</td>
<td><strong>Metal loss</strong> &gt; 50%</td>
<td><strong>Gouge</strong> &gt; 12.5%</td>
</tr>
</tbody>
</table>

In short, the below approach may be followed for mitigation actions:

- Integrity assessment results
- Mitigation actions evaluated?
  - Critical activities or activities requiring special focus
  - Normally undertaken activities
- Incorporate additional frequencies or include actions in subsequent Annual Maintenance Plans
- Develop plans for all such critical or special activities and include in subsequent business and yearly plans, including allocation of resources
The plans for critical activities shall be reviewed periodically by the company to address the resources (means) requirement and necessary changes in organizational and external factors affecting integrity management.

6.1.5 Update, integrate and review data:
After the initial integrity assessments are completed, the results shall be maintained in soft and/or hard 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 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 company’s pipeline assets.

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 program.

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

1) Process measures e.g. Number of damages per excavation notification received
2) Operational measures e.g. No. of significant ILI anomalies
3) Direct integrity measures e.g. No. of damages per km. of pipeline length

The company shall conduct periodic audits to validate the effectiveness of its integrity management programs and ensure that they have been conducted in accordance with the plan.

A list of essential items is provided below in developing a company integrity management and performance evaluation program:

1) An integrity management policy and program for all applicable elements shall be in place
2) Written integrity management plan procedures and task descriptions are up to date and readily available
3) Activities are performed in accordance with the plan
4) Individuals have received proper qualification and training for activities which they are to undertake
5) The integrity management program meets the requirements of this document
6) All required activities are documented
7) All action items or non-conformances are closed in a timely manner
8) The risk criteria used have been reviewed and documented.
9) Prevention, mitigation, and repair criteria have been established, met, and documented.
10) Data developed from program-specific performance indicator measures, results of internal benchmarking, and audits shall be used to provide an effective basis for evaluation of the integrity management program.

### 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 IMS 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 & specific problems.

<table>
<thead>
<tr>
<th>Goals</th>
<th>Performance Measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>To maintain pipeline Pipe-to-Soil Potential (PSP) within acceptable limits</td>
<td>PSP Level</td>
</tr>
<tr>
<td>Execution of ILI pigging</td>
<td>As applicable</td>
</tr>
<tr>
<td>Leakage and ruptures</td>
<td>Number</td>
</tr>
<tr>
<td>Development, Training and Awareness programs</td>
<td>Number of training and awareness programs conducted in a year</td>
</tr>
<tr>
<td>No ROU encroachments</td>
<td>Number of encroachments</td>
</tr>
</tbody>
</table>

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 IMS required activities completed.
- The number of defects found requiring repair or mitigation.
- The number of leak 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 as locate request.
• 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 program takes appropriate advantage of improved technology and that the program 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 causes analysis of pipeline breakdowns & accidents
• Process enhancement / changes(MOC),
• Recommended changes for the IMS,
• Additional training requirements necessary to support IMS,
• Public awareness program
• 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 program.

Based on results of the internal reviews, integrity assessment & mitigation program shall be improved & documented.
6.3 COMMUNICATION PLAN

The pipeline company shall develop and implement a communications plan in order to keep appropriate company personnel, jurisdictional authorities, and the public informed about their integrity management efforts and the results of their integrity management activities. The information may be communicated as part of other required communications.

6.4 MANAGEMENT OF CHANGE PLAN

Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity.

A management of change process includes the following:
(1) Reason for change
(2) Authority for approving changes
(3) Analysis of implications
(4) Acquisition of required work permits
(5) Documentation
(6) Communication of change to affected parties
(7) Time limitations
(8) Staff involved
(9) Planning for each situation
(10) Unique circumstances if any

6.5 QUALITY CONTROL PLAN

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 program (e.g. ISO-9001-2001) maintained by the entities. The following activities shall be made part of quality control program:

(i) Identify and maintain the document required for Integrity management plan procedures and records. This includes both controlled and uncontrolled documents.

(ii) Defining Roles & responsibilities for implementation of programme, documentation etc.

(iii) Review 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 /required to improve the integrity management plan or quality plan

Internal Audits 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 IMS.

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 on for any internal audit and external audit of the entire IMS:

- 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 program, 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 program for all elements
- Written IMS procedures and task descriptions are up to date and readily available.
- Activities are performed in accordance with the IMS.
- A responsible individual has been assigned for each task.
- Individuals have received proper qualification-Same to be documented.
- 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.
CONTROL OVER INTEGRITY

A pipeline company shall have in place various controls which need to be put over the various stages, to achieve sound integrity management. The various stages are described below:

7.1 DESIGN

Integrity management of a pipeline starts with a sound design and construction of the pipeline. The company shall ensure that relevant standards (including PNGRB standards and those referenced in it) are applied to the design and designer considers the area the pipeline traverses and the possible impacts that the pipeline may have on that area and the people that reside in the vicinity. The company shall maintain a document for Basis of Design, and all the pipelines laid by it and all other facilities covered by it shall be covered in the Basis of Design document.

7.2 PROCUREMENT & SUPPLY CHAIN

The company shall ensure that purchased products confirm to specified purchase requirements. The purchase specifications should be reviewed on a regular basis. The company shall evaluate and select suppliers based on their ability to supply to its specifications.

The critical items shall be inspected by a Quality Control / Assurance team and / or by certified third party agencies.

The key integrity measures for Procurement are:
- Selection of appropriate suppliers
- Compliance with specifications
- Positive material identification where appropriate
- Deviations recorded and documented
- Procurement and Quality Assurance system

7.3 FABRICATION, CONSTRUCTION, INSTALLATION & TESTING STAGE

The company shall ensure that pipework and other components are fabricated, constructed, inspected and tested in compliance with the specifications developed for different purposes (in compliance with PNGRB and its referenced standards and industry practices). Quality of fabrication, construction, installation has to be assured by conducting quality audits, by
appointing TPIs, etc. The means of ensuring compliance with specifications shall be addressed and deviations to planned arrangements shall be recorded. For critical items, company should invoke independent inspection, even if only on a sampling basis.

The key integrity measures for Fabrication, Construction, Installation and Testing are:

- Compliance with design & construction specifications
- Appropriate fabricators
- Quality control / assurance
- Construction documentation
- Deviations / concessions recorded
- Confirmation of integrity as appropriate (pressure testing / NDT etc.)
- Commissioning plans and procedure

### 7.4 SYSTEM HANDOVER / TAKEOVER

The company shall ensure that the transfer of responsibility between life stages (e.g. from Construction to Commissioning and Operation) needs to be agreed (through established procedure and checklists) and to be formalized by preparing punch lists for pending items with agreed action plans. All the relevant documents shall be transferred from one stage to the next stage (as per the procedure / checklists).

The key integrity measures for System handover / takeover are:

- Established system / procedure
- Compliance with specifications

### 7.5 COMMISSIONING

Plans and procedures shall be prepared for safe commissioning. Pre commissioning checks, tool box talk and safe control operations are the tools to assure mechanical integrity of system under commissioning.

A readiness review shall be conducted with all relevant functions involved for major projects before commissioning. Modifications found necessary shall be adequately controlled to ensure integrity is maintained.

### 7.6 OPERATIONS

The company shall establish its operations philosophy and implement it by operations management procedures and controls developed by it. It shall provide adequate operational controls and procedures to avoid
adverse incidents impacting the health, safety and security of the work force, the environment.

Clear, up-to-date procedures and instructions shall be available to cover normal operating conditions, emergencies and management of changes. Safe operating levels shall be defined to demarcate between normal operating deviations and operating outside the design envelope.

The key integrity controls for operations are:

- Operating instructions /procedures which have clearly defined operating boundaries including allowable start-up / shutdown excursions
- Emergency procedures
- System for operational alarms and their handling and management
- Procedure for management of changes
- Adequate management systems to ensure operational efficiency
- Pipe work is operated within agreed boundaries
- Reporting of abnormal operation, or excursions beyond operational boundaries including notification for actions

7.7 IN-SERVICE INSPECTION, TESTING, MAINTENANCE, REPAIRS & REPLACEMENT

The company shall define a maintenance philosophy and this Maintenance Philosophy document should be the guiding document for all of its inspection, testing and maintenance, which includes maintenance, inspection and testing procedures for each piping system (including pipelines and station pipelines).

Inspection and testing resources for pipe work should be appropriately focused using techniques such as written examination checklists to identify which system to inspect, and what inspection methods to employ. The approach for inspection and testing shall be mentioned in the maintenance philosophy.

The company shall also have preventive maintenance initiatives in place. These processes should be specifically targeted to minimize identified risks. Examples include

- Initiatives to minimize third party damages
- Pipeline patrolling - to monitor activity near pipelines
- Leakage management process
- Scheduled maintenance - to minimize equipment malfunction
- Corrosion management process
- Replacements - to replace unserviceable installations

The capability for effective response to leaks and equipment breakdown or malfunction should be maintained on a 24 hr, 7 days a week basis.

7.8 INSTRUMENTATION & ELECTRICAL

Instrumentation and electrical management system shall be geared towards maintaining the Instrumentation & Electrical assets in good working order to ensure an optimal operational management during the planned operational life cycle while complying with the company policy. This shall be achieved by planning and implementing a comprehensive maintenance plan for assets and ancillary equipment that protects the health and safety of personnel, protects the environment, protects and preserves the company’s capital investment, and enables targeted performance.

1. Minimizing the number of equipment failures
2. Planning of repairs to ensure minimum disruption
3. Monitoring for wear and tear and random failures

7.9 DE-COMMISSIONING, DISMANTLING, DEMOLITION & DISPOSAL

Plans and procedures shall be developed for safe decommissioning, dismantling, demolition and disposal. These should also address isolation, decontamination and environmental issues.

Each pipeline abandoned in place shall be disconnected from all sources and supplies of petroleum and petroleum products; purged of petroleum and petroleum products and sealed at the ends (usually with the use of end caps). However, the pipeline may not be purged when the volume of petroleum and petroleum products is so small that there is no potential hazard.

Whenever supply to a delivery terminal is discontinued, one of the following shall be done.

- The valve that is closed to prevent the flow of petroleum and petroleum products to the terminal shall be provided with a locking device or other means designed to prevent the opening of the valve by persons other than authorized persons;
• A mechanical device or fitting that will prevent the flow of petroleum and petroleum products shall be installed in the line or somewhere along the assembly;
• The terminal’s piping shall be physically disconnected from the petroleum and petroleum products supply and the open pipe ends sealed; or
• Each abandoned chamber shall be filled with a suitable compacted material.
SCHEDULE 8

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., 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.

The document shall be agreed at Board level of the entity, constantly and systematically reviewed and updated, and all levels of management 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:

8.1 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 team of the entity
- Step#4: Conformity of IMS document with the Regulation by Third Party Inspection Agency (TPIA)

8.2 ACCEPTANCE BY PNGRB

- Step#5: Acceptance by PNGRB

8.3 APPROVAL FOR IMPLEMENTATION

- Step#6: Approved for implementation by CEO/Director of the entity.

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 PNGRB that the Pipeline Integrity Management system is in line with the requirements of the various regulations issued by the PNGRB from time to time and has been approved by the CEO/Director of the company.
## SCHEDULE-9

### IMPLEMENTATION SCHEDULE of IMS:

<table>
<thead>
<tr>
<th>Sr. No.</th>
<th>Activities</th>
<th>Time Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Preparation of IMS document and approval by Head of Operation</td>
<td>1 year from date of notification of these regulations</td>
</tr>
<tr>
<td></td>
<td>team of the entity.</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Conformity of IMS document with regulation by TPIA.</td>
<td>3 months from the approval by Head of Operation team of the entity.</td>
</tr>
<tr>
<td>3</td>
<td>Submission of IMS document to PNGRB</td>
<td>1 month from the conformity of IMS by TPIA</td>
</tr>
<tr>
<td>4</td>
<td>Approval for implementation by the entity</td>
<td>Within 3 months from the acceptance of IMS document by PNGRB</td>
</tr>
<tr>
<td>5</td>
<td>Submission of Compliance to PNGRB</td>
<td>03 months after approval at Sr. No. 4 above</td>
</tr>
</tbody>
</table>

**Note:** Steps for implementation to be followed as described in Schedule-8
REVIEW OF THE INTEGRITY MANAGEMENT SYSTEM

10.1 Periodicity

Entities shall review their existing IMS every 3 years based upon the:
(i) Revised Baseline data
(ii) Critical Inputs from various departments

10.2 Review of IMS by PNGRB

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

(a) Internal Audit as per the checklist for natural gas pipelines provided by PNGRB shall be carried out by the management of operator every year.

(b) External Audit (EA) by third party, approved by the Board, as per the methodology specified by the PNGRB every 3 years.
CRUDE OIL PIPELINES INTEGRITY ASSESSMENT

An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. The corrosive effect of the crude oil on the pipeline must be investigated and adequate steps must be taken to mitigate internal corrosion considering inhibition and monitoring. Liquids / solids collected during cleaning pig runs must be sampled, analyzed, and assessed with regard to internal corrosion mitigation. In addition to Integrity assessment tools mentioned in this Regulation, specific parameters to be monitored for crude oil pipelines must include Basic sediment and Water (BS&W) as percentage of volume transported, Density of the oil and Kinematic Viscosity at reference temperatures maintained by the entity.

11.1 Surveillance methods

The following surveillance methods must be considered for implementation

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Monitoring methods</th>
<th>Time period Frequency for implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>DESCALING OF PIPELINES (PIGGING)</td>
<td>Pipelines transporting crude petroleum and liquid petroleum products shall be descaled as per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014. Pig residue collected after descaling shall be examined to monitor the condition of the pipeline and to determine the subsequent frequency of descaling.</td>
</tr>
<tr>
<td>2</td>
<td>INSPECTION OF SACRIFICIAL ANODE</td>
<td>Once in three years</td>
</tr>
<tr>
<td>3</td>
<td>CONTINUOUS POTENTIAL SURVEY</td>
<td>Continuous Potential Logging survey shall be done once in five years.</td>
</tr>
<tr>
<td>4</td>
<td>CHECKING OF LEAK DETECTION SYSTEM</td>
<td>Leak Detection System shall be checked and calibrated for accuracy and effectiveness of operation as per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014.</td>
</tr>
<tr>
<td></td>
<td>INSPECTION OF VALVE, PATROLLING, CORROSION ASSESSMENT AND MITIGATION, SURVEYS</td>
<td>As per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014.</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>7</td>
<td>INSPECTION OF LOAD LIFTING EQUIPMENT</td>
<td>All load lifting equipment, wire ropes, tackles etc. shall be inspected once in year. Factory's Act shall be referred for guidance.</td>
</tr>
<tr>
<td>8</td>
<td>INSPECTION OF TELECOMMUNICATION SYSTEM/EQUIPMENT</td>
<td>Detailed System functional tests shall be carried out once in six months. Telecommunication equipment shall be inspected as per manufacturer's recommendation.</td>
</tr>
<tr>
<td>9</td>
<td>INSPECTION OF TELEMETRY SYSTEM/EQUIPMENT</td>
<td>Detailed System functional tests shall be carried out once in six months. Telemetry equipment shall be inspected as per manufacturer's recommendation.</td>
</tr>
<tr>
<td>10</td>
<td>INTELLIGENT PIGGING</td>
<td>As per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014. The results of subsequent inspections shall be compared with original commissioning date in order to assess the health of the pipeline and subsequent periodicity of intelligent pigging.</td>
</tr>
<tr>
<td>11</td>
<td>WELD REPAIR AND INSPECTION</td>
<td>All weld repair and inspection shall be carried out in accordance with provisions of API 1104, API 1107, API 2200, API 220.</td>
</tr>
<tr>
<td>12</td>
<td>HYDROSTATIC TESTING OF PIPELINES</td>
<td>Pre-tested pipe shall be used for all replacements in line with the requirements of ANSI B.31.4 and ANSI B.31.8 and API 1100. Other requirements in accordance with the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014.</td>
</tr>
</tbody>
</table>
SCHEDULE- 12

BLACK-OIL PIPELINES INTEGRITY ASSESSMENT

In addition to Integrity assessment tools mentioned in this Regulation, specific parameters to be monitored for black oil pipelines must include Basic sediment and Water (BS&W) as percentage of volume transported, Density of the oil and Kinematic Viscosity at reference temperatures maintained by the entity.

12.1 Surveillance methods

The following surveillance methods must be considered for implementation

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Monitoring methods</th>
<th>Time period Frequency for implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>DESCALING OF PIPELINES (PIGGING)</td>
<td>Pipelines transporting Black Oils shall be descaled initially every six months. Pig residue collected after descaling shall be examined to monitor the condition of the pipeline and to determine the subsequent frequency of descaling.</td>
</tr>
<tr>
<td>2</td>
<td>INSPECTION OF SACRIFICIAL ANODE</td>
<td>Once in three years</td>
</tr>
<tr>
<td>3</td>
<td>CONTINUOUS POTENTIAL SURVEY</td>
<td>Continuous Potential Logging survey shall be done once in five years.</td>
</tr>
<tr>
<td>4</td>
<td>CHECKING OF LEAK DETECTION SYSTEM</td>
<td>Leak Detection System shall be checked and calibrated for accuracy and effectiveness of operation as per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014.</td>
</tr>
<tr>
<td>5</td>
<td>INSPECTION OF VALVE, PATROLLING, CORROSION ASSESSMENT AND MITIGATION, SURVEYS</td>
<td>As per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014 for crude oil pipelines.</td>
</tr>
<tr>
<td>6</td>
<td>INSPECTION OF LOAD LIFTING EQUIPMENT</td>
<td>All load lifting equipment, wire ropes, tackles etc. shall be inspected once in year. Factory's Act shall be referred for guidance.</td>
</tr>
<tr>
<td></td>
<td>INSPECTION OF TELECOMMUNICATION SYSTEM/EQUIPMENT</td>
<td>Detailed System functional tests shall be carried out once in six months. Telecommunication equipment shall be inspected as per manufacturer’s recommendation.</td>
</tr>
<tr>
<td>---</td>
<td>--------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>8</td>
<td>INSPECTION OF TELEMETRY SYSTEM/EQUIPMENT</td>
<td>Detailed System functional tests shall be carried out once in six months. Telemetry equipment shall be inspected as per manufacturer’s recommendation.</td>
</tr>
<tr>
<td>9</td>
<td>INTELLIGENT PIGGING</td>
<td>As per the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014. The results of subsequent inspections shall be compared with original commissioning date in order to assess the health of the pipeline and subsequent periodicity of intelligent pigging.</td>
</tr>
<tr>
<td>10</td>
<td>WELD REPAIR AND INSPECTION</td>
<td>All weld repair and inspection shall be carried out in accordance with provisions of API 1104, API 1107, API 2200, API 220.</td>
</tr>
<tr>
<td>11</td>
<td>HYDROSTATIC TESTING OF PIPELINES</td>
<td>Pre-tested pipe shall be used for all replacements in line with the requirements of ANSI B.31.4 and ANSI B.31.8 and API 1100. Other requirements in accordance with the provisions of PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Product Pipelines) Regulations, 2014.</td>
</tr>
</tbody>
</table>
### SCHEDULE-13

**OFFSHORE PIPELINES INTEGRITY ASSESSMENT**

Offshore pipelines are those pipelines which carry crude petroleum or its products from producing sources, such as, well-head platforms or from Single buoy mooring system to main platforms in the offshore and are transporting crude petroleum or its product from main platform or Single buoy mooring system to the place where facilities are available to receive them on hand.

13.1 **Surveillance methods**

The following surveillance methods must be considered for implementation:

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Monitoring methods</th>
<th>Time period</th>
<th>Frequency for implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>FREE SPAN SURVEY</td>
<td></td>
<td>Annually</td>
</tr>
<tr>
<td>2</td>
<td>LATERAL DISPLACEMENT SURVEY</td>
<td></td>
<td>Annually</td>
</tr>
<tr>
<td>3</td>
<td>DESCALING OF PIPELINES (PIGGING)</td>
<td></td>
<td>Pipelines transporting crude petroleum and liquid petroleum products shall be descaled annually. Pig residue collected after descaling shall be examined to monitor the condition of the pipeline and to determine the subsequent frequency of descaling.</td>
</tr>
<tr>
<td>4</td>
<td>INSPECTION OF SACRIFICIAL ANODE</td>
<td></td>
<td>Once in three years</td>
</tr>
<tr>
<td>5</td>
<td>CONTINUOUS POTENTIAL SURVEY</td>
<td></td>
<td>Continuous Potential Logging survey shall be done once in five years.</td>
</tr>
<tr>
<td>6</td>
<td>DEBRIS CLEANING</td>
<td></td>
<td>Debris cleaning should be done once in six months</td>
</tr>
<tr>
<td>7</td>
<td>CHECKING OF LEAK DETECTION SYSTEM</td>
<td></td>
<td>Leak Detection System shall be checked and calibrated for accuracy and effectiveness of operation once in three months.</td>
</tr>
<tr>
<td>8</td>
<td>INSPECTION OF VALVE</td>
<td></td>
<td>Valves shall be partially operated and inspected once in six months to ensure operability at all times.</td>
</tr>
<tr>
<td>9</td>
<td>INSPECTION OF LOAD LIFTING EQUIPMENT</td>
<td></td>
<td>All load lifting equipment, wire ropes, tackles etc. shall be inspected once in year. Factory's Act shall be referred for guidance.</td>
</tr>
<tr>
<td></td>
<td>INSPECTION OF TELECOMMUNICATION SYSTEM/EQUIPMENT</td>
<td>System functional tests shall be carried out daily. Telecommunication equipment shall be inspected as per manufacturer's recommendation.</td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>INSPECTION OF TELEMETRY SYSTEM/EQUIPMENT</td>
<td>System functional tests shall be carried out daily. Telemetry equipment shall be inspected as per manufacturer's recommendation.</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>INTELLIGENT PIGGING</td>
<td>The Pipeline should be inspected once in 5 years for corrosion / dents / pits etc. by means of electronic / intelligent pigging. The results of subsequent inspections shall be compared with original commissioning date in order to assess the health of the pipeline and subsequent periodicity of intelligent pigging.</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>WELD REPAIR AND INSPECTION</td>
<td>All weld repair and inspection shall be carried out in accordance with provisions of API 1104, API 1107, API 2200, API 2201 shall be referred for guidance.</td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>HYDROSTATIC TESTING OF PIPELINES</td>
<td>Pre-tested pipe shall be used for all replacements in line with the requirements of ANSI B.31.4 and ANSI B.31.8 and API 1100</td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX-1

REFERENCES

(see Regulation 3)

REFERENCE STANDARDS, CODE OF PRACTICE & GUIDELINES:

1) ASME B31.4- PIPELINE TRANSPORTATION SYSTEMS FOR LIQUID HYDROCARBONS AND OTHER LIQUIDS.
2) ASME B31Q - PIPELINE PERSONNEL QUALIFICATION
3) ASME B31G - MANUAL FOR DETERMINING THE REMAINING STRENGTH OF CORRODED PIPELINES
4) API STANDARD 1160- MANAGING SYSTEM INTEGRITY FOR HAZARDOUS LIQUID PIPELINES
5) NACE Standard RP0502-2002
6) AS 2885.1-1997 Pipelines - Gas and liquid petroleum - Design and construction
7) AS 2885.2-1995 Pipelines - Gas and liquid petroleum - Welding
<table>
<thead>
<tr>
<th>Sr. No.</th>
<th>Critical infrastructure/ activity/ processes</th>
<th>Time period for implementation</th>
<th>Implementation plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Cathodic Protection survey to ensure an integrated CP system</td>
<td>6 months for survey</td>
<td>Implementation plan to be submitted</td>
</tr>
<tr>
<td>2</td>
<td>Intelligent Pigging</td>
<td>2 Years</td>
<td>If the pigging has not been done for more than 10 years for pipeline, then the intelligent pigging shall be carried out within two years.</td>
</tr>
<tr>
<td>3</td>
<td>GIS mapping</td>
<td>2 years</td>
<td>Implementation plan to be submitted</td>
</tr>
<tr>
<td>4</td>
<td>Leak detection system implementation</td>
<td>6 months</td>
<td>Through SCADA and APPS system.</td>
</tr>
<tr>
<td>5</td>
<td>Baseline Data for IMS</td>
<td>6 months</td>
<td></td>
</tr>
</tbody>
</table>

* commencement of implementation
# Appendix-III

## Suggestive Chart for selection of Integrity Assessment method with respect to specific threat

<table>
<thead>
<tr>
<th>Threat Group</th>
<th>Threat</th>
<th>Preferred Integrity Assessment / Assurance Method</th>
<th>Assessment interval</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Time-Dependent</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>External Corrosion</td>
<td>Hydrostatic test, Inline inspection, ECDA</td>
<td>Max. 10 year**</td>
</tr>
<tr>
<td></td>
<td>Internal Corrosion</td>
<td>Hydrostatic test, Inline inspection, ICDA</td>
<td>Max. 10 year**</td>
</tr>
<tr>
<td></td>
<td>Stress Corrosion cracking</td>
<td>Inline inspection, SCADA</td>
<td>Max. 10 year**</td>
</tr>
<tr>
<td><strong>Stable</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a) Manufacturing related defects</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Defective Pipe Seam</td>
<td>Hydro-test (Post Construction), Inline inspection</td>
<td>Before commissioning or as and when required</td>
</tr>
<tr>
<td></td>
<td>Defective Pipe</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>b) Welding / Fabrication related</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Defective Pipe Girth Weld</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Defective fabrication Weld</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Wrinkle bend or buckle</td>
<td>Caliper pigging / EGP</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Stripped threads/broken pipe</td>
<td>Visual Examination / Gas Leakage Survey</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c) Equipment</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gasket / O-ring Failure</td>
<td>Visual Examination / Gas Leakage Survey</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Control / Relief equipment malfunction</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Visual Examination / Gas Leakage Survey</td>
<td></td>
</tr>
<tr>
<td><strong>Time-Independent</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>a) Third Party / Mechanical Damage</td>
<td>Damage inflicted by first, second, or third parties (Instantaneous / Immediate failure)</td>
<td>Public Education (See Communication Plan &amp; preventive actions), Patrolling, ROW</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Monthly / quarterly</td>
</tr>
<tr>
<td>Maintenance, External Protection, IESS</td>
<td>Previously damaged pipe (delayed failure mode)</td>
<td>Above + Leakage Survey, Rehabilitation</td>
<td></td>
</tr>
<tr>
<td>--------------------------------------</td>
<td>-----------------------------------------------</td>
<td>-----------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Vandalism</td>
<td>All above</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Change in geometry</td>
<td>EGP survey (Once in three years)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

b) Incorrect Operations

<table>
<thead>
<tr>
<th>Incorrect Operational procedure</th>
<th>Compliance Audits</th>
</tr>
</thead>
</table>

b) Incorrect Operations

<table>
<thead>
<tr>
<th>Weather related and Outside Forces</th>
<th>Weather related</th>
<th>Leakage survey, Surveillance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lightning</td>
<td>Surge diverters</td>
<td>NA</td>
</tr>
<tr>
<td>Heavy rains or floods</td>
<td>Anti-buoyancy inspection, Surveillance</td>
<td></td>
</tr>
<tr>
<td>Earth Movements</td>
<td>Strain monitoring, Leakage survey.</td>
<td></td>
</tr>
</tbody>
</table>

1) Note: * Some of the important Integrity Assessment Methods have been briefed in Schedule-5 of these regulations.

2) Inline inspection frequency to be as per PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum & Petroleum product Pipelines) Regulations as and when notified by the Board

3) Abbreviations:
   - ECDA – External Corrosion Direct Assessment
   - ICDA – Internal Corrosion Direct Assessment
   - SCCDA – Stress Corrosion Cracking Direct Assessment
   - ILI – In Line Inspection (Intelligent Pigging)
## APPENDIX-IV
### Minimum Qualification and Experience for Field Personnel in Project Phase as well as O&M Stage

<table>
<thead>
<tr>
<th>Discipline</th>
<th>Tier-I</th>
<th>Tier-II Supervisor Level</th>
<th>Tier-III Operator Level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical</td>
<td>Degree In Mechanical Engineering</td>
<td>Diploma In Mechanical Engineering + at least 1 year of Experience</td>
<td>Plymouth with at least 1 year experience in the relevant field of operation / or 10th standard with minimum 3 years experience in the relevant field</td>
</tr>
<tr>
<td>Instrumentation &amp; Control</td>
<td>Degree In I&amp;C / Electronics Engineering</td>
<td>Diploma In I&amp;C / Electronics + at least 1 year of Experience</td>
<td>Plymouth with at least 1 year experience in the relevant field of operation</td>
</tr>
<tr>
<td>Electronics &amp; Communication</td>
<td>Degree In Electronics or Communication Engineering</td>
<td>Diploma In Electronics or Communication Engineering + at least 1 year of Experience in SCADA</td>
<td>Plymouth with at least 1 year experience in the relevant field of operation</td>
</tr>
<tr>
<td>Electrical</td>
<td>Degree In Electrical Engineering</td>
<td>Diploma In Electrical Engineering + at least 1 year of Experience</td>
<td>Plymouth with at least 1 year experience in the relevant field of operation</td>
</tr>
<tr>
<td>Fire &amp; Safety</td>
<td>Equivalent Degree In F&amp;S Engineering</td>
<td>Diploma In F&amp;S Engineering / at least 1 year of Experience</td>
<td>Plymouth with at least 1 year experience in the relevant field of operation</td>
</tr>
<tr>
<td>Civil</td>
<td>Degree In Civil Engineering</td>
<td>Diploma In Civil Engineering + at least 1 year of Experience</td>
<td>Plymouth with at least 1 year experience in the relevant field of operation</td>
</tr>
</tbody>
</table>

**Note:** Each Petroleum and Petroleum product Pipeline shall have SME (Subject Matter Expert) having qualification in any of the discipline mentioned above with minimum 5 years of relevant experience.