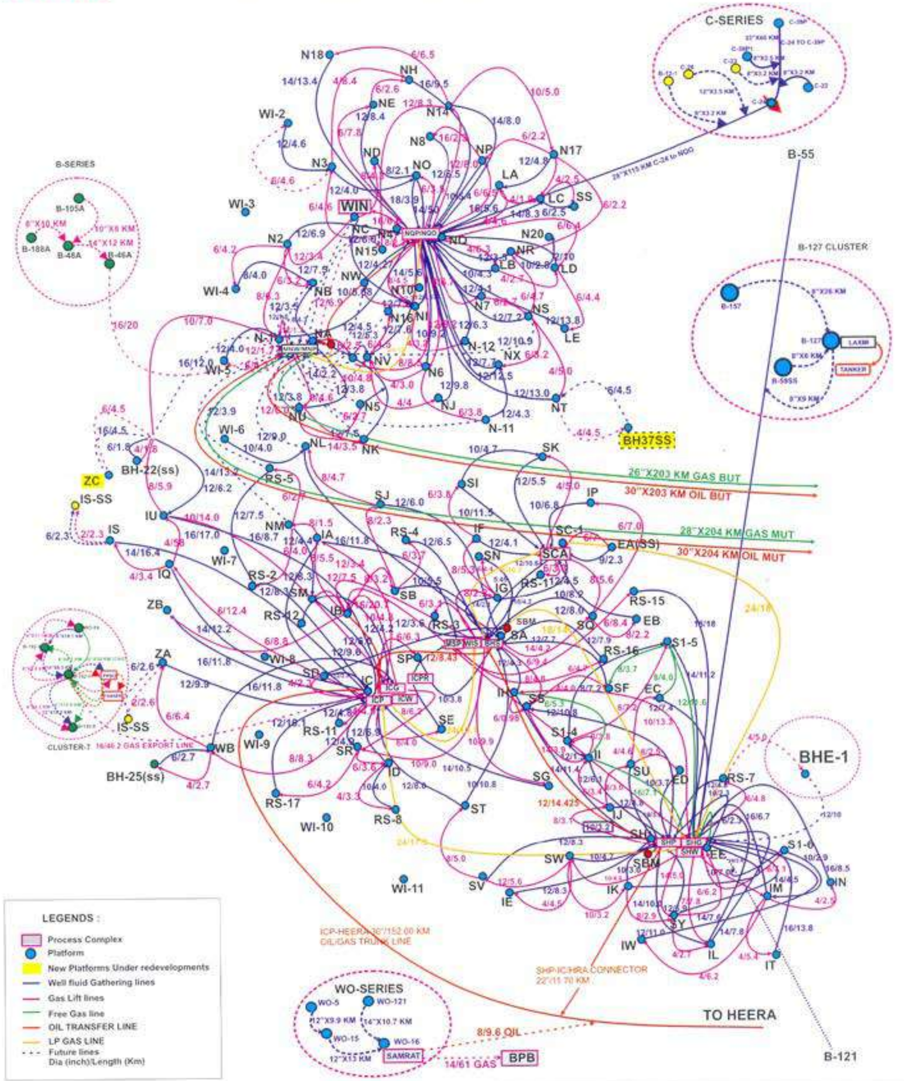
Pipeline Integrity Management – Learning from Failures

Maushumi Kakoti Talukdar
Chief Chemist
ONGC

INTRODUCTION

- Oil & Gas transportation pipelines are lifelines of energy business, economy of a country and global economy
- Drastic reductions in both investments and operating costs can be achieved when unprocessed, multiphase well fluids are transported through pipelines.
- ONGC is operating a vast pipeline network of 643 pipelines, which includes 637 subsea pipelines 6 Uran to Trombay product pipelines.
- Pipline network in western offshore is having a cumulative length of 6184 km

MUMBAI HIGH AND MARGINAL FIELD WELL FLUID AND GAS LIFT NETWORK



- Though they are well protected against external corrosion by sacrificial anodes, control of internal corrosion always remains a big challenge.
- A leakage of well fluid lines not only cause production loss but also is a hazard to the marine environment .
- Marine pipelines are constructed of high-strength carbon steels in several grades, depending on size, internal operating pressure, bending and longitudinal stresses expected during construction, and anticipated environmental conditions.

All piping, materials, and fittings are specified to be consistent with industry standards, promulgated by technical societies such as the American Petroleum Institute and the American Society of Mechanical Engineers. OPS and MMS regulations specify minimum operating design and construction, post-construction, and testing standards for pipelines and components. Both agencies regulations cite these industry standards frequently

Risks for Pipeline Integrity and Operation

Manufacturing
Steel Production
Welding (SAW, ERW)

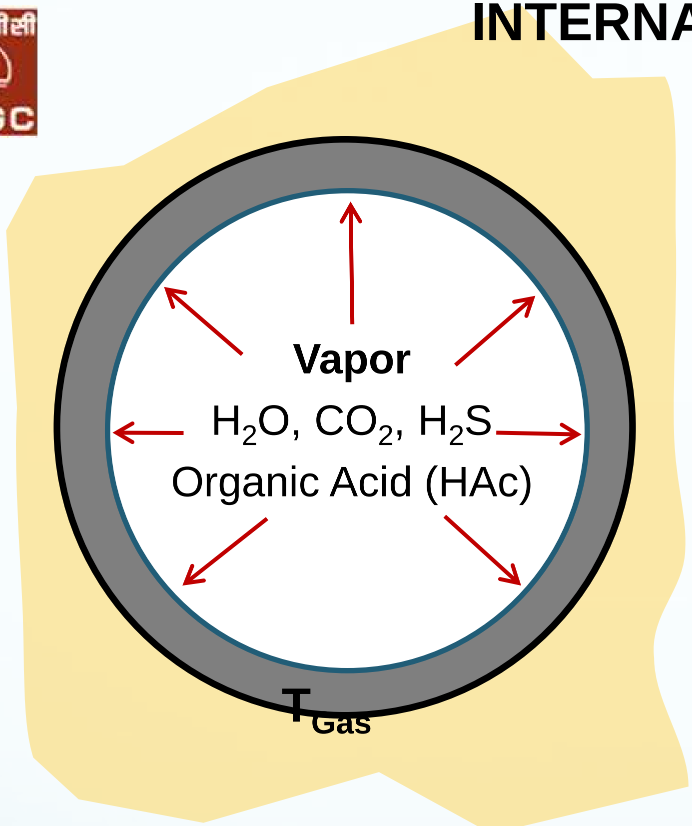
Operational
mechanical damage,
stress/fatigue type
material failures, internal and
external corrosion etc

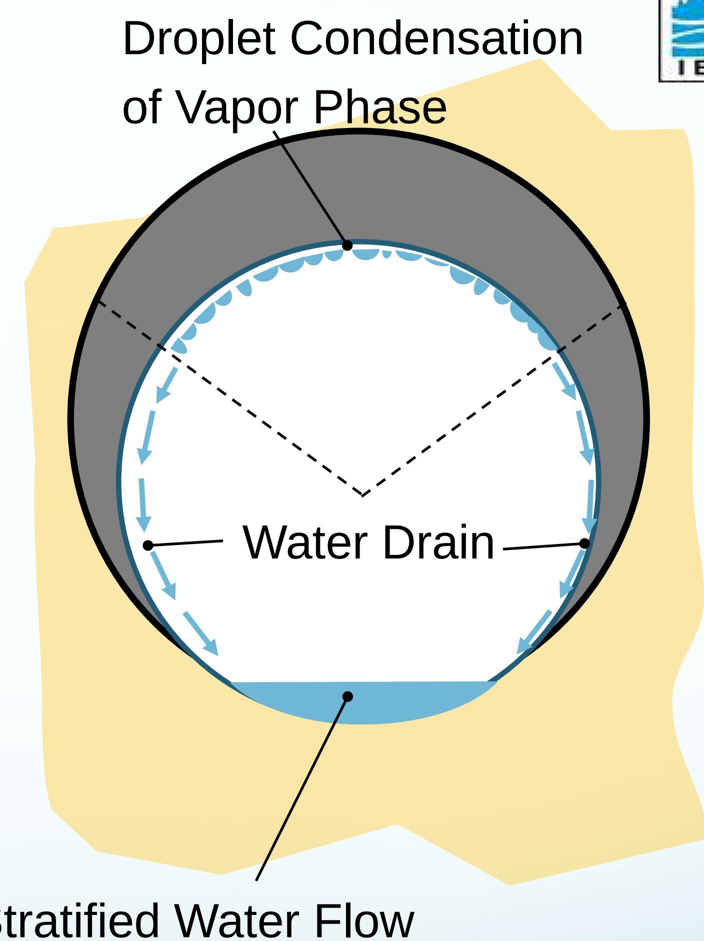
Pipeline Integrity Assessment

Construction
Girth Weld Faults
Poor Pipe Support

Coating and CP
Poor Surface Preparation
Inadequate Material Storage

FACTORS RESPONSIBLE FOR INTERNAL CORROSION





- Partial Pressure of CO_2
- Partial Pressure of H_2S
- Water Condensation Rate
- Gas Pressure, Velocity, Flow regime, Temperature
- Organic Acid (HAc) Concentration

- Presence of ions in the fluid gives rise to corrosion product mostly Iron Carbonate in presence of CO_2 which gets deposited on the pipe surface.

- When corrosion products are not deposited on the pipe surface, very high corrosion rates of several millimeters per year can occur.

- The corrosion rate reduces substantially under conditions where iron carbonate ($FeCO_3$) is precipitated on the pipe surface and form a dense and protective corrosion product film. This occurs more easily at high temperature or high pH in the water phase.

- When H2S is present in addition to CO_2, iron sulphide (FeS) films are formed rather than $FeCO_3$, and protective films can be formed at lower temperature, since FeS precipitates much easier than $FeCO_3$.
- Localised corrosion with very high corrosion rates can occur when the corrosion product film does not give sufficient protection, and this is the most feared type of corrosion attack in oil and gas pipelines.

FAILURE ANALYSIS CASE STUDIES

CASE STUDY -1

- This 7.2 km long 12” dia well fluid line was carrying oil and gas from one platform to another, failed after a service life of 5 years.
- Four numbers of sub sea leakages at 6 O’clock position were reported in this line.
- The material of the construction of pipeline was API 5LX-60 (CS NACE) with the designed thickness of 14.3mm.

There is a long rupture which is reported to be at the 6 O’clock position.

In the internal surface there was localized corrosion in the form of a canal throughout the length of the pipelines. There is heavy metal loss in the canal resulting in the formation of slits and holes.

OPERATING PARAMETERS

Sl. no.	Particulars	well fluid Line
1.	Flow rate :(a) liquid flow rate (b) Oil (c) Water flow rate (d) Total Gas (e) Water cut	2288.45 BLPD 930.995 BOPD 1357.46 BWPD 15423 SCM^3/d 59%
2.	H_2S, ppm	85-95 ppm
3.	Mole % CO_2	2.0-2.5%
4.	Pigging frequency	Total 19 pigging operations have been carried out at an average quarterly frequency. Last pigging done was on 25.03.2011.
5.	Corrosion monitoring techniques i) External corrosion ii) Internal corrosion	Regular Iron Count

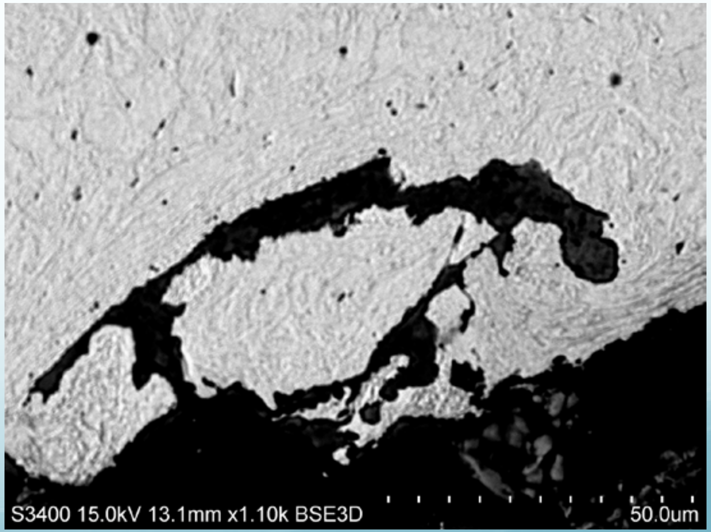
LABORATORY INVESTIGATIONS

- Chemical composition analysis, mechanical testing results and microstructure analysis confirm the material to be API 5LX-60 (CS NACE) .

- Metallurgical studies reveal that corroded surfaces were devoid of protective layer of Iron Carbonate scales.

- Produced water analysis reveals presence of VFA to be 876 ppm with 17000 ppm of chloride.

SEM micrograph showing progress of mesa attack as observed on polished and etched samples



CONCLUSION

- Results from various studies confirm that the pipeline failed due to localized carbon di oxide corrosion. Pipeline was found to be continuously water wet at 6O’ clock. Presence of 865 ppm of Volatile Fatty Acid and a pH of 6.4 is responsible for removal of the protective Iron carbonate layer on the water wet zone.

- All the laboratory investigations supported by the literature reveal that the conditions prevailing in the pipeline was suitable for a CO_2 mesa corrosion attack to take place. SEM studies as well as inverted microscopic studies reveal that the localized corrosion mechanism was that of mesa type of carbon di oxide corrosion which deepened and caused the ultimate failure of the pipeline.

CASE STUDY-2

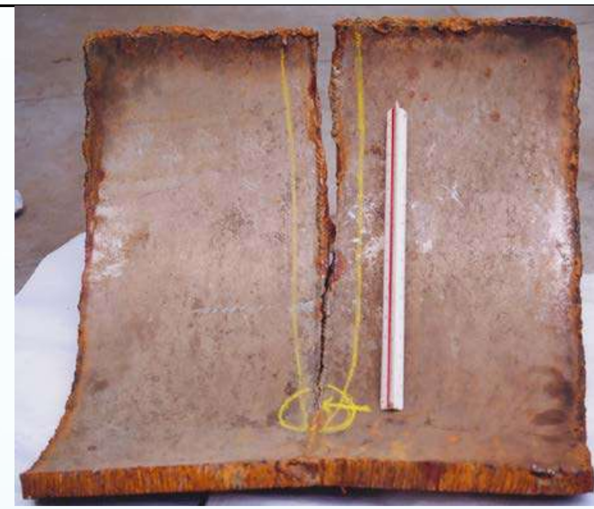
- This 24” sub sea well fluid line was found to have prematurely failed.
- Leak developed in the form of crack/split from 10 o/c to 8 o/c through 12 o/c.
- The material of the construction of pipeline was API5L Gr.X65 with incoloy cladding with a designed thickness of 20.00 mm.
- At the time of failure, pipeline was operating at the pressure of 80 kg/cm2
- After the leakage pipeline length of 11.29 mts. replaced

CASE STUDY-2

Sl. No.	Particulars 24" Ø WF Line	
1	Operating temp	82-110°c
2	Operating pressure	65-90 Kg/cm2
3	Flow rate : a) Condensate (b) Gas (c) Water	 940m3/d 5.0498 mmsm3/day 122 m3/d
4	H_2S, ppm	80-170 ppm
5	Mole % CO_2	1.67-3.91
6	Pigging Details	Not done as it is incoloy cladded

LABORATORY INVESTGATIONS

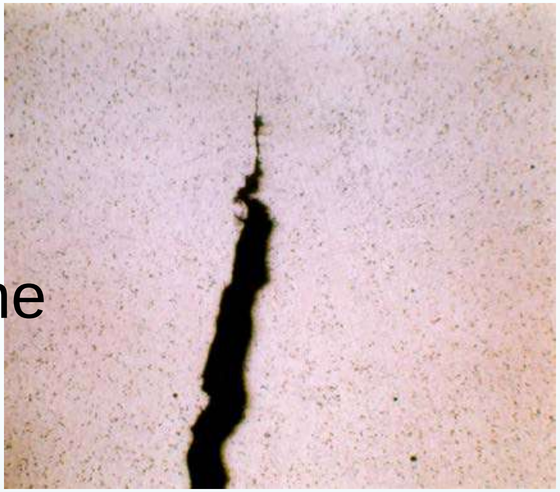
- Visual inspection revealed the opening of the burst along the circumferential weld. The slit was zig zag in appearance. No external and Internal corrosion.

	
External surface of the failed pipeline.	*Internal surface of the failed pipeline*

- Radiography indicated no weld defect.
- Hardness test indicated area near the crack was locally hardened.

METALLURGICAL ANALYSIS

The crack has initiated at the HAZ of the carbon steel pipe and has propagated into weld metal



The tip of the crack was found at the weld metal zone

Near the tip of the main crack another microcrack was also seen at the weld metal This crack lies on hard zone typically found in dissimilar metal welds

CONCLUSION

- Various studies conclude that cracks resulting from hydrogen embrittlement is the most probable cause of rupture of this well fluid line as the cracks are found to be initiating and propagating in a direction transverse to the weld in the pipe.
- Several such transverse cracks have reduced the strength of the weld and when it could not withstand the operating pressure of the pipeline, the pipe failed in a brittle mode.
- During welding of the line hydrogen might got dissolve in molten weld pool

Experience after six years of failure

- Just after the failure it was replaced by a carbon steel pipe without any cladding and after 6 years of service, no thickness reduction of the carbon steel portion of the pipeline was observed.

- The protective layer formed by FeS has remained intact as the pipeline is not pigged.

CORROSION CONTROL

- The marine environment is a challenging one for pipelines, and maintaining their integrity requires vigilance. Repairs and inspection are costly for underwater pipelines, and the emphasis is accordingly on preventing damage and deterioration.

- Corrosion protection has advanced to a state at which pipelines may serve far beyond their original expected service lives. Much of the pipeline inventory has remained in use beyond its originally intended service life.

There are few methods available for internal corrosion control of sub sea pipelines.

- Corrosion inhibitor when added to an environment would effectively reduce the corrosion rate of a metal exposed to the environment. Active compound of the inhibitor form a layer on the metal surface prevent water from touching the pipe wall.
- Batching, followed by a continuous injection programme, is recommended over a injection programme alone, as there is no way to ensure that all of the pipe wall has been treated. The continuous injection of corrosion inhibitor can be accomplished by the use of gravity pumps with flow regulation

- In gas / condensate lines adding hydrate inhibitors like Glycol or methanol reduces the corrosion rate.

- Corrosion rate in gas/ condensate line can be substantially reduced by increasing the pH of the water phase.
- Protective layer to isolate pipe wall to corrosive environment can also be achieved by composite coating/linings.
- CRA e.g Incoloy is used to replace carbon steel where high corrosivity is anticipated.
- As CRA is too expensive so it is used after assessing overall economics.

- Corrosion especially internal corrosion is inexorable, and requires continual inspection and monitoring. This problem is likely to grow more serious; as gas fields decline, gas pipelines will carry more liquids, and be potentially subject to increasing corrosion.
- The corrosion management is crucial since failures can invoke the danger of professional, regulatory or legal snafus.

- The best approach, is to reconcile the design investment at the capital expenditure (CAPEX) stage with the operating expenditure (OPEX) incurred during the life of the asset with materials selection, materials fabrication, materials performance, and corrosion assessments that are based on the whole life of the asset.

- The corrosion threat is handled by various corrosion control, protection and monitoring measures and process control.
- Detailed plans are drawn to mitigate various threats and those plans are executed to avoid / minimize them. This has resulted in significant improvements in and effectiveness of pipeline integrity management.
- Various hardware and software contribute to these plans.

CORROSION MONITORING

- Corrosion monitoring is the practice of measuring the corrosivity of the fluid flowing through the pipeline.
- Successful corrosion inhibition programme always incorporates monitoring.
- In order to take maximal benefit, efficiency of corrosion inhibitor dosing must be monitored.
- The monitoring tools also help in optimization of inhibitor dose.
- The optimum techno economic gains can be drawn from the internal corrosion inhibition programme if inhibition and monitoring are implemented together.

- Large number of corrosion monitoring techniques exist. Conventional techniques which are used in industrial applications:
- Iron Count
- Corrosion Coupons (weight loss measurements)
- Electrical Resistance (ER) probe
- Linear Polarization Resistance (LPR) probe

Pigs are used in oil and gas pipelines to clean the pipes. There are also "smart pigs" used to inspect pipelines for the purpose of preventing leaks that can be explosive and dangerous to the environment.

- In segregated flow regime, where water separates out and accumulate at the bottom of the line in these lines pigging will have better response. Analysis of the pigging debris will also throw light on corrosivity of the fluid.

DATA MANAGEMENT

- Records are fundamental to a corrosion control programme.
- Typical ingredients of database for corrosion management are:
- Design information
- Operating data
- Monitoring data
- Inspection data

With these data base and regular corrosion audit results in review of the existing conditions of the pipeline vis-à-vis an effective corrosion management.

CONCLUSION

- However, over the life span of a pipeline, there may happen several changes in the external and internal environment that may pose new threats to the integrity of a pipeline.
- Pipeline integrity management is a contonuous process.

THANK YOU

For your patient hearing