Applying Non-Traditional ILI Technology to Challenging Pipeline Segments for Transmission Integrity Management

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This paper will provide an overview of 15 projects conducted by Pacific Gas and Electric Company (PG&E) using emerging non-traditional ILI technologies, grouped by the type of challenge faced. The use of these methods and technologies are increasingly important to the pipeline industry, to perform challenging integrity assessments. Additionally, a detailed review of one 20” inspection conducted with a robotic tool through a hot-tap on an in-service natural gas pipeline will also be reviewed.
EXECUTIVE SUMMARY

The use of non-traditional in-line inspection (non-traditional-ILI) methods and tools has become increasingly valuable in managing the integrity of gas transmission pipeline systems. From late 2012 through December of 2014, Pacific Gas & Electric Co. (PG&E) conducted 15 non-traditional ILI projects for Transmission Integrity Management purposes. The use of non-traditional ILI is becoming an increasingly important part of PG&E’s strategy to reduce system risk and maintain reliability. In addition, projects using in-line video inspection tools have been conducted for identification and pinpointing the location of internal pipeline features. Determination of the most appropriate non-traditional ILI method and ILI tool requires rigorous data gathering and analysis. Each method and tool has to be evaluated to identify the most effective approach for individual project scenarios. The numerous methods that are available to conduct non-traditional ILI inspections are varied, each offering its own distinctive set of capabilities. Given the unique challenges and nuances between execution methods and tool types, prior experience and project team continuity have proven beneficial in successfully completing non-traditional ILI projects from project scoping through planning and execution.

Inspection challenges in which non-traditional ILI methods have proven to be effective include the inspection of water crossings, cased spans, road/highway crossings, extended casings and inserted pipe sections, and Direct Assessment required dig locations that are subject to abnormally difficult permitting and construction requirements. This paper will discuss the use of non-traditional ILI to solve inspection challenges and provides key observations and lessons learned from 15 projects executed between August 2012 and December 2014.

An in-depth review is provided for one project from the data gathering and project scoping phase through project execution. The project was conducted in 2013 on a 20” pipeline traversing a creek crossing which had been identified as an Internal Corrosion Direct Assessment (ICDA) excavation. Due to long-lead environmental permitting requirements, the ICDA project was at-risk to extend beyond its required completion date. PG&E, GTS, and Pipetel Technologies conducted a successful non-traditional ILI of the target location. A unique solution was developed by the project team in response to two of the key project challenges; a problematic pipeline shutdown and the requirement to inspect a 45° elbow at the creek bottom.

Non-traditional ILI has proven to be a valuable addition to a pipeline operator’s toolkit for both Integrity Management and other transmission pipeline investigations. Numerous inspection challenges can be overcome utilizing the appropriate non-traditional ILI methods such as; long-lead permits and construction challenges for Direct Examination locations, casing inspections, waterway crossings, and validation of pipeline features.
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INTRODUCTION

The term “non-traditional ILI” for the context of this paper, refers to performing in-line inspection of pipeline segments considered challenging or unpractical to inspect using traditional free-swimming ILI tools. These pipeline segments may not be suitable or cost effective to utilize traditional ILI methods due to the presence of unpiggable features, low pipeline pressure conditions, or their short length. Non-traditional ILI methods include the use of various internal inspection technologies including tethered and untethered robotic technologies, tethered MFL technology, and also the use of traditional free-swimming ILI tools that are strategically deployed at targeted locations such as waterway crossings. Free-swimming ILI tools may be propelled using a variety of methods including natural gas, nitrogen, or a liquid medium such as water or diesel.

The importance of the strategic deployment of non-traditional ILI has become apparent to PG&E over the last three years based in-part on an in-depth system evaluation conducted in 2013. PG&E discovered that many short sections of pipe located in High Consequence Areas (HCAs) posed an equally high or higher risk to public safety compared to longer sections of pipe slated for Traditional ILI. Despite their short length, these sections of pipe could not be overlooked for ILI. With PG&E’s goal is to inspect as much of the transmission system with ILI as possible, and the fact that portions of the system are challenging or impractical to inspect for traditional ILI, non-traditional ILI has become a key component of PG&E’s ILI program targeting difficult segments to inspect in high-priority locations.

In addition to transmission pipeline system features there are other considerations for the use of non-traditional ILI. These include short sections with high risk to public safety and reliability, lengthy permitting and construction challenges, as well as pipeline segments where the use of Direct Assessment methods are impractical or infeasible. Utilizing non-traditional ILI techniques allows the project team to identify a nearby excavation location for ILI tool insertion that is not subject to the same permitting and/or construction challenges of excavating directly at the location of interest. In cases where Direct Assessment is impractical, such as at cased spans, non-traditional ILI provides the operator with a method for validating the integrity of the pipeline without hydrostatic testing, and to obtain component specific data for the inspection area. Having non-traditional ILI tools and techniques available to conduct necessary integrity assessments has proven to be an invaluable tool in PG&E’s Transmission Integrity Management Program’s tool box and has allowed them to meet crucial deadlines and to maintain a safe transmission pipeline system.

OVERVIEW OF PG&E NON-TRADITIONAL ILI PROJECTS

Between August 2012 and December 2014, PG&E conducted 15 non-traditional ILI projects for Transmission Integrity Management purposes. Inspections have been performed on pipelines ranging from 6” outside diameter (OD) to 36” OD, and include tethered and untethered robotic tools, tethered MFL (Magnetic Flux Leakage) tools, as well as free-swimming traditional ILI tools utilizing temporary launcher & receivers installed in-field to inspect targeted locations. The robotic tools used have included video, MFL, EMAT (Electro Magnetic Acoustic Transducer), and Eddy Current inspection technologies. The 15 projects discussed in this paper do not include additional in-line video projects which have also been utilized by PG&E for various transmission pipeline projects such as verifying longitudinal seam weld types, verifying the presence and exact location of internal drips, farm taps and pinpointing other pipeline features for investigative purposes. Many of the pipeline segments included in this paper were assessed by In Line Inspection in accordance with 49 CFR 192, Subpart O and ASME
B31.8S, Section 6.2. In cases where non-traditional ILI has been used at locations identified for Internal Corrosion Direct Assessment (ICDA), PG&E’s ICDA Risk Management Procedure allows for the use of ILI tools as a Direct Examination technique and are thus considered assessed by ICDA. The project categories below are grouped based on common challenges associated with the types of identified pipeline segments:

**WATERWAY CROSSINGS**

Waterway crossings represent a significant portion of PG&E’s non-traditional ILI project portfolio; eight of the 15 projects included in this paper reside in this category. Waterway crossings range from dry seasonal streams to large rivers, as well as lined and unlined irrigation & storm water canals. Excavating these locations is often challenging for multiple reasons, primarily due to a combination of extensive long-lead environmental permitting and construction challenges. In the case of irrigation canals there is also the issue of maintaining an uninterrupted water supply to regional agricultural areas.

PG&E has conducted non-traditional ILI projects on transmission pipelines at waterway crossings utilizing untethered robotic MFL tools, as well as tethered robotic tools utilizing EMAT, Eddy Current, and video technologies. Temporary launchers and receivers have been strategically deployed in the field to inspect targeted crossings utilizing “traditional” free-swimming MFL/Geometry combination tools. Based on the age of many pipelines, 1.5D and miter bends are common, and permitting the replacement of these features for manufactured longer-radius bends is challenging and costly in today’s environment. As a result, tethered MFL tools may not be feasible at many of these locations.

In pipelines with ODs 10” and greater, robotic tools are often used due to their ability to navigate restrictive bend combinations. Also, launching robotic tools is generally less expensive and time consuming than welding launcher and receivers required for free-swimming ILI tools. In the case of tethered robotic tools, having a cable attached to the tool can serve as a contingency plan in the event that an emergency tool recovery is needed.
For pipelines less than 10” in OD, there are fewer robotic tools presently available\(^1\), therefore free-swimming traditional MFL tools are often utilized. The use of free-swimming ILI tools allows for the option of cleaning the target inspection area which has the added benefit of removing excess liquids and sediment, potentially enhancing the data quality of the inspection. However, projects utilizing free-swimming ILI tools tend to have increased costs associated with additional construction such as welding temporary launchers and receivers and added time for pipeline cleaning.

Entry points for ILI tools at waterways must be evaluated based upon the most economical and feasible options and take into account the environmental sensitivity of the area, permitting duration and requirements, pipeline depth, and overall impact to the surrounding area. These locations also tend to be low points in the pipeline making them susceptible to liquids accumulation which must be taken into account during the project planning and ILI tool selection process. If significant liquids are encountered, it can impact the ability of many robotic ILI tools to successfully complete the inspection and potentially result in a tool’s electronics being damaged or the tool becoming stranded in the pipeline.

**CASED SPANS**

Above-grade cased spans can pose a unique challenge for assessing pipeline segments with Direct Assessment methods. Standard casing inspections cannot be conducted due to the fact the pipe is not buried, and visual inspection of the carrier pipe cannot be conducted since it is enclosed within a casing\(^2\). In 2014 PG&E conducted two inspections of above-grade cased spans.

One project inspected approximately 1,000’ of a 10” OD pipeline inside a 16” OD casing that was contained within the structure of a two-lane bridge spanning a major river crossing. A non-tethered robotic MFL tool was chosen to conduct this inspection. This allowed the tool entry point to be located

\(^1\) Technologies are under development and newly available within this size range that offer additional robotic ILI tool options for future projects.  
\(^2\) Mini robotic technologies are emerging to conduct visual and in some cases ultrasonic spot testing within the annular space between casing and carrier pipe, although attaining 100% visual inspection remains problematic with this technique given the presence of spacers and sometimes debris within the annular space.
in a field, and a safe distance away from the main road, roughly 180’ from the onset of the casing. This entry point allowed for safe staging and work areas required minimal permitting and land owner agreements and did not impact the bridge traffic. This project was also executed without taking an outage which minimized the impact to gas system operations and staff.

The second project inspected an 8” OD pipeline inside a 12” OD casing, which was attached to the outside of a bridge via pipe hangers and spanning a river some 239’. An 8” tethered MFL tool was selected for this project in part because a convenient location and above-grade access was available at the end of the cased span to launch the tool, and because full coverage of the span including metal loss data could be obtained. This tool was inserted at one end of the bridge and propelled to the opposite side by compressed air. Once the tool reached the end of the casing, a winch was used to pull the tool back to the starting point. After the tool run, the ILI vendor determined that the last ~ 2’ of the cased span was not inspected since the ILI tool could not pass further into the bend at the end of the casing. The project team was able to remove the end of the casing not inspected by the ILI tool and perform a Direct Examination in order to complete the inspection.

CONSTRUCTABILITY

Five non-traditional ILI projects have been conducted due to construction-driven challenges at locations originally planned for Direct Assessment excavations. In all cases the cost and challenges associated with each method were evaluated and the non-traditional ILI option was executed after it was determined to have either a lower cost and/or greater likelihood of success than the excavation option.

One project was a 30” OD pipeline approximately 1,500’ up a mountainside in an environmentally sensitive area. Excavating the Direct Assessment required dig locations at this location would have required transporting all equipment up difficult terrain by hand, and manual digging in rocky soil. The location was also at high risk of not being completed in time due to an upcoming deadline. The non-traditional ILI was ultimately executed with a tethered MFL tool and coordinated in conjunction
with the planned shutdown of the pipeline for a nearby replacement project. The entire non-traditional ILI project was completed 18 days after project initiation.

A 12” OD inspection project was conducted via tetherless robotic MFL while the pipeline system remained in operation in order to inspect three low points for internal corrosion. This inspection was utilized to provide the Transmission Integrity Management engineering team with additional data from which to evaluate the overall internal corrosion threat within the pipeline.

An additional 12” OD inspection project was initiated due to a challenging Direct Assessment location which was located in unstable soil conditions and adjacent to a structural foundation. The project was also conducted via tetherless robotic MFL while the pipeline system remained in operation. The scope was expanded to ~3,400’, which was the maximum feasible from a single entry point based on the specific tool utilized. Doing so allowed the engineering team to satisfy the original project objective of inspecting the pipe at the unstable soil location, while also inspecting nearby locations identified by the Indirect Inspection Tool (IIT) results previously conducted as part of the ECDA (External Corrosion Direct Assessment) program with minimal added cost.

One 30” OD inspection project was conducted at a location in which construction was underway as an ECDA casing inspection, but was shut down prior to completion of the assessment when a traffic control-related dispute erupted between the two permitting agencies. The timeframe to resolve the dispute between the two agencies and the eventual restrictions placed on construction hours made meeting the rapidly approaching compliance deadline doubtful. A cross functional project team of PG&E ILI Engineering and GTS Project Managers coordinated with a nearby replacement project for shared resources and a planned pipeline outage, allowing for successful project execution in six days from project inception to ILI execution.

The other of these projects was on a 24” OD pipeline requiring an internal corrosion inspection at a low point that traversed underneath a 60” diameter sewer line adjacent to a major freeway. A tethered robotic EMAT tool was identified for this inspection along with another nearby inspection of a creek crossing on the same pipeline. These locations were known to have liquids present, and because the EMAT tool requires a clean pipeline, a chemical cleaning program requiring a launcher and receiver was designed and implemented. This added measure ensured the pipeline at the two targeted low points was sufficiently clean to allow the tool to obtain quality data.

**DETAILED INSPECTION PROFILE: 20” OD CREEK CROSSING WITH PIPETEL EXPLORER 20/26**

**PROJECT INTRODUCTION**

As part of PG&E’s 2013 Direct Assessment Program, an internal corrosion inspection on a 20” OD pipeline at a low point in a creek crossing was required to be completed prior to the end of 2013. The inspection needed to encompass the entire creek bottom, the downstream sag elbow and the adjacent downstream pipe for a total inspection length of 48’. The pipeline at the crossing was installed in 1960, had a wall thickness of 0.312”, and included a 45° 1.5D sag elbow with a wall thickness of 0.500”. The method originally identified to conduct the inspection was to excavate and perform direct examination of the subject pipe and fitting. However, because of the extensive permits required, the project was at-risk to be completed prior to its required completion date. As a contingency the permitting for the originally planned direct examination process proceeded, but in parallel the
project team began gathering the necessary data and performing an analysis to determine if a non-traditional ILI project would be a viable option.

**SCOPING PROCESS**

The project team gathered and analyzed the available pipeline records including the pipeline features list (PFL) and as-built drawings to determine critical project parameters including pipeline diameter and feature characteristics important to non-traditional ILI tool navigability. Additionally, the team reviewed aerial imagery and conducted a site visit to determine viable locations to gain access for ILI tool insertion. Gas planning and operations staff were contacted to determine the practicality of conducting a pipeline shutdown within the target timeframe, and to solicit information regarding the expected level of liquids and general pipeline cleanliness at the crossing.

Based on the scoping analysis, three key challenges were identified:

**Inspection of Elbow**

Based on engineering analysis, the 45° sag elbow on the downstream side of the creek was determined to be the likely point for liquids to gather if present in the pipeline. It was also determined that this was the primary location where internal corrosion would occur, and therefore, the central focal point of the inspection. Based on PG&E’s procedure, the bottom 180° of the fitting was to be inspected for internal corrosion.

This requirement posed a challenge for the non-traditional ILI project team to identify a tool capable of collecting data inside the fitting. Many ILI tools experience sensor liftoff inside elbows resulting in decreased resolution in bends, and some are unable to gather any information at all at these types of fittings.
**Long Lead Permitting**

The location of the key sag bend resides within a creek bottom which would be subject to a Streambed Alteration Agreement permit from the California Department of Fish & Wildlife, as well as a permit from the Regional Water Quality Control Board. As a contingency the permitting for the originally planned direct examination process proceeded in parallel with the non-traditional ILI project scoping process. Although these permits were ultimately obtained in September, the specific construction and mitigation requirements related to those permits made the execution of a Direct Examination (dig) of the elbow within the creek bed infeasible prior to the deadline. The non-traditional ILI project had to ensure the ILI tool entry point was a sufficient distance from the creek to eliminate the need for any long-lead permitting.

**Problematic Shutdown**

After a hydraulic analysis was performed by transmission system planning and the project was discussed with gas system operations staff, it was determined that taking the pipeline at the creek crossing out of service would have placed a significant strain on operational resources. Although the project team could have pursued this option, doing so would have required moving resources away from a number of other impacted projects in the area. Additionally, Compressed Natural Gas (CNG) would have been required in order to supply customers with uninterrupted service.

Multiple options were investigated for implementing a temporary pipeline bypass around the creek; however all were determined infeasible within the project timeframe due to permitting constraints and significant community & property owner impact.

**SOLUTION DETERMINED**

In order to overcome the scheduling challenge, the team was able to identify multiple viable options for non-traditional ILI tool entry points near the inspection point but located far enough away from the creek bank to eliminate the need for any long-lead permits. Locations upstream and downstream were identified that could accommodate both robotic tools as well the installation of a launcher and receiver for free-swimming tools.

The issue of the operationally infeasible pipeline shutdown was overcome by use of the Piptel Explorer robotic MFL tool with its “hot-tap” launch & retrieve ability. This method allows for the untethered battery-powered robotic tool to be launched, conduct an inspection, and exit the pipeline via a pressure control fitting (PCF) without requiring a system shutdown. This method would allow the pipeline to remain in-service under normal operating pressure (NOP) for the duration of the inspection while requiring only minimal support from gas operations staff during project execution, and
eliminating the need for CNG resources.

The last remaining key issue was the inspection of the target elbow. In order to minimize the potential of damage to the MFL sensor, Pipetel typically retracts the sensor when passing through fittings. This method would not be acceptable for conducting this inspection because of the assessment requirement to inspect the bottom 180° of the elbow. After conducting an engineering evaluation, Pipetel determined a solution based on the fact that each of the Explorer tool’s MFL sensor blocks can be deployed and/or retracted individually. The evaluation showed that greatest threat of tool damage was present at the top (12 o’clock position) of the sag bend. Pipetel determined that by deploying only the sensor blocks covering the bottom 270° of the pipeline circumference, the risk of tool damage could be minimized while also fully magnetizing and obtaining the required data for the bottom 180° of the fitting. This technique would allow the key inspection criteria to be satisfied while also minimizing the risk of tool damage during inspection of the fitting.

KEY PROJECT PLANNING CONSIDERATIONS

Once the solutions to the key challenges of the project had been determined, the non-traditional ILI project was presented to the project sponsors. The project was authorized to proceed and the project team moved forward with the detailed project planning and preparations. A temporary construction easement with the land owner adjacent to the excavation location was obtained and engineered construction drawings were then prepared. Construction activities such as excavation, welding, hot-tapping, and pipe fitting were planned, scheduled and coordinated by the Project Management team. Gas system operations staff worked with Pipetel to develop a valve operations plan, and community outreach efforts were conducted to ensure all local authorities and surrounding land owners were made aware of the project and its potential impact to the immediate area. Contracts were initiated and secured between the project sponsor and the necessary vendors; Pipetel, the tapping and plugging vendor, the excavation vendor, and the welding and pipe fitting vendor.

Given the large cross-functional project team which included multiple outside contractors, a detailed Sequence of Operations was developed to ensure that all team members had a clear understanding of who was to provide what service and/or materials. This plan outlined the details of each task to be performed on each day along with relevant details, such as arrival time of vendors and identification of the responsible person on site. A Risk Analysis was also performed to identify project risks and a contingency plan was developed specifying courses of action should a contingency scenario arise.
Additional key planning items also included the following:

**Pipeline Cleanliness & Potential for Liquids**

The Pipetel Explorer 20/26 tool is able to conduct inspections with some pipeline liquids present, however if a significant amount of liquid is encountered it would pose a risk to the integrity of the tool. Since this segment of pipeline had not been cleaned and a cleaning program was not feasible due to the project constraints, significant effort was put forth to determine the level of risk associated with pipeline cleanliness and likelihood of liquids in the crossing. Key operations personnel were interviewed and data was obtained from nearby replacement projects as part of this investigation.

The data obtained indicated a low risk for debris and for standing liquids in the crossing, and as a result the project team accepted this as an inherent risk, with the understanding that if liquids more significant than expected were encountered, that the tool would be unable to complete the inspection. The Explorer tool’s high resolution video capability would identify standing liquids in the pipeline at the time of the inspection.

**Pipeline Depth & Above vs. Below Grade Access to Launcher**

As part of the design engineering the project team needed to determine if access to the launcher door was to be above or below grade based on the pipeline depth. Had the pipeline depth been shallow, the launcher access would have been above-grade requiring cribbing support to the launch tube and potentially scaffolding for safe access when loading the tool. Based on pipeline depth information obtained it was determined that below-grade access would be required for this project. There were two options the project team considered; fabricate an extension for the Pipetel launch tube to bring the launcher door above-grade, or develop a solution to allow for below-grade access to the launcher door. Based on the project schedule and the cost associated with each option, the solution selected was to excavate a shallow trench adjacent to the main bellhole, long enough to accommodate the horizontal portion of Pipetel’s launcher. In order to limit the length of the trench, during project execution the tool was to be loaded into the horizontal portion of the launch tube prior to installing the launch tube onto the riser and elbow. This solution allowed for adequate access to the launcher while limiting the costs associated with fabricating a launcher riser extension or with doubling the length of the below-grade trench.
Support for Pressure Control Fitting (PCF)

Due to the materials and equipment utilized for the hot-tap launch method, the Project Engineer and Manager identified a concern with the total weight being applied to the pipeline within the 15 foot long excavation. The materials and equipment included the 20” PCF (1,210 lbs.), sandwich valve (5,090 lbs.), tapping machine (4,893 lbs.), and the launch tube assembly (~9,900 lbs.). In order to alleviate strain on the pipeline due to the significant weight of the materials, the engineering and construction teams installed temporary cribbing underneath the PFC fitting to ensure adequate support was maintained at the location of concern for the duration of the ILI operation.

Risk of Tool Damage

Although the top 90° of the MFL sensor blocks were to remain retracted when inspecting the elbow, some risk of damaging the sensors during project execution did remain. In order to mitigate this risk, Pipetel ensured there were sufficient spare parts and key technical personnel available on-site. In the event the sensor was damaged during the inspection the tool could be repaired overnight and a contingency inspection could be attempted the following day.

EXECUTION & RESULTS

The project was successfully executed on October 29, 2013 and the critical data inside the bottom of the target elbow obtained without damage to the tool. A minor delay occurred during the nitrogen purge & pressure testing of the launch tube assembly when a connection between two of the flanges failed the soap test indicating a leak. Tools and appropriate crew members were onsite and deployed to re-tighten the bolts connecting the two flanges and the leak was eliminated.

During the inspection, the tool experienced a minor technical issue resulting in a 2.1% data loss between the 9:00 o’clock – 11:30 positions, however the ILI engineer determined that given the location of the data loss that no re-run was required and that the run was successful. The creek crossing was successfully inspected for internal corrosion, meeting the inspection deadline and revealing no internal anomalies and five minor external anomalies.

CONCLUSIONS

VALUE OF NON-TRADITIONAL ILI TO PIPELINE OPERATOR'S TOOLBOX

Non-traditional ILI methods have consistently proven to be a valuable asset within PG&E’s toolbox. Many critical compliance-driven Integrity Management inspections have been completed via non-traditional ILI in cases where permitting and conducting Direct Assessment would have been infeasible by the deadline, and/or where construction would be abnormally challenging or expensive. In addition to Integrity Management assessments, non-traditional ILI has also proven to be a useful tool for other transmission pipeline projects such as validating
pipeline properties such as seam weld types, pipe wall thickness, and internal pipe wall markings / stenciling. Non-traditional ILI has also been used in support of other projects to pinpoint exact locations of pipeline features such as internal drips and reducers in preparation for future pipeline replacement and hydrostatic testing.

LESSONS LEARNED

No Single Tool for Every Job

A key lesson learned over the last three years is that there is no single non-traditional ILI tool or execution method that can solve every challenging inspection. Each project must undergo a rigorous analysis to understand its unique requirements, conditions, and constraints in order to determine the most appropriate execution method and ILI tool. Key constraints that must be considered include pipeline size, schedule requirements, ability to isolate the pipeline segment, pipeline system planning, engineering and construction resource availability, and ILI tool vendor availability.

Analysis & Determination of Execution Method and ILI Tool

The first step in this process is the data gathering and analysis including the PFL, key as-built documents, and the operations history for information related to likely cleanliness and presence of liquids. Entry points must be identified considering site constraints, permitting and schedule requirements, as well as ILI tool capabilities related to distance and feature navigation. Interviews must be conducted with operator personnel to determine key project parameters such as the required inspection coverage, the types of anomalies expected and the likelihood they will be discovered, as well as the feasibility and timing to take the pipeline segment out of service.

Based on the specific project requirements and constraints, the project team must evaluate potential ILI tools and vendors most suitable for the particular inspection. Potential vendors must review the project details and confirm the project as feasible for both the tool and for the schedule requirements.

In instances where standard non-traditional ILI tools and methods do not yield the required results, working closely with ILI tool vendors may reveal unique and innovative solutions not readily apparent during the initial project evaluation.

Detailed Project Planning and Coordination

Rigorous project management and engineering have proven to be critical to the success of non-traditional ILI projects. After the initial project scoping and confirmation of the specific execution method and ILI tool vendor, ensuring a complete cross-functional team with all key disciplines represented is a critical component of a successful project. This team, at a minimum should consist of ILI and Design Engineering, Project Management, Gas Operations, Land/Environmental, Construction, Permitting, and Community Outreach.

A detailed project task list and work plan that builds off of lessons-learned from prior projects, regular team meetings, communications, and review of key project materials must be conducted to ensure critical details are identified and accounted for. Some of the materials that must be reviewed by key project stakeholders include; the design engineering and construction drawings, traffic control plans and permitting exhibits/materials, as well as outage planning documents and external communications materials. Contingency planning must also be part
of any successful project as the risk of a stuck or damaged tool, or incomplete inspection is a possible for any project.

Regardless of how many times a team has conducted a particular type of project, each job has its own unique circumstances that must be thoroughly vetted in the planning process to ensure all project details are identified and accounted for prior to execution.

OUTLOOK FOR FUTURE USE

As of 2015 PG&E has initiated a non-traditional ILI program targeting high risk pipeline sections which are not practical to inspect using traditional ILI, casings with known hard contacts and long sections of inserted pipe within highly-populated areas, as well as underneath highway crossings. In response to pipelines with MAOP too low for traditional ILI tools, PG&E is also working with vendors to develop low pressure / low drag free swimming ILI tools. The Direct Assessment program will certainly continue to identify challenging locations for inspection subject to environmental permitting and construction challenges, which will likely continue to be a driver for future non-traditional ILI projects. Additional validation of pipeline features for various purposes will also likely continue into the future.