NORTHEAST GAS ASSOCIATION

November 6, 2023

US Department of Transportation
Docket Management System
West Building, Ground Floor, Room W12-140
1200 New Jersey Ave., SE
Washington, DC 20590-0001

Attention: Docket No. PHMSA-2021-0046

Re: In the Matter of the Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives Notice of Proposed Rulemaking and Request for Revision Comments of The Northeast Gas Association

Via Email

Dear Sir or Madam:

The Northeast Gas Association[1] ("NGA") respectfully submits the following comments and request for revision on behalf of our natural gas local distribution company members ("NGA LDCs") in response to the above referenced Notice[2].

PHMSA proposes revisions to the pipeline safety regulations to require operators of gas distribution pipelines to update their distribution integrity management programs (DIMP), emergency response plans, operations and maintenance manuals, and other safety practices. These proposals implement provisions of the Leonel Rondon Pipeline Safety Act—part of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act) and a National Transportation Safety Board (NTSB) recommendation directed toward preventing incidents resulting from overpressurization of low-pressure gas distribution systems similar to that which occurred on a gas distribution pipeline system in CMA Merrimack Valley

[1] NGA is a regional trade association that focuses on pipeline safety and safety culture, education and training, technology research and development, operations, planning, and increasing public awareness of natural gas in the Northeast U.S. NGA supports a culture of pipeline safety and environmentally responsible energy delivery practices. NGA represents natural gas distribution companies, transmission companies, liquefied natural gas suppliers and associate member companies. Its member companies provide natural gas service to 14 million customers in 9 states (CT, MA, ME, NH, NJ, NY, PA, RI, VT).

[2] Pipeline Safety: Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives, Federal Register Vol. 88, No. 172 (September 7, 2023).

1800 West Park Drive., Ste. 340, Westborough, MA 01581 20 Waterview Blvd., 4th Floor, Parsippany, NJ 07054
781.455.6800, 973.265.1900
www.northeastgas.org

incident on September 13, 2018. Further, PHMSA proposes other pipeline safety initiatives for all part 192-regulated pipelines, including gas transmission and gathering pipelines, such as updating emergency response plans and inspection requirements.

Major pieces of the proposal with potential impacts to NGA membership includes:

- Enhancing to construction procedures designed to minimize the risk of incidents caused by system overpressurization.
- Updating Distribution Integrity Management Programs to minimize the threat of and learn from over-pressurization incidents.
- Requiring new regulator stations to be designed with two separate methods of overpressure protection and remote gas monitoring, to better prepare gas distribution systems to avoid overpressurization, and limit damage during incidents.
- Strengthening emergency response plans for gas pipeline emergencies, including requirements for operators to contact local emergency responders and keep customers and the affected public informed of what to do in the event of an emergency.

Many of the proposed requirements are specific to low-pressure systems, which are particularly sensitive to the consequences of a system malfunction or event that may cause overpressurizaton. The CMA Merrimack Valley incident was a tragic event that reminded the industry of the unique risks associated with low-pressure systems, where options for pressure regulation are limited due to the science of delivering gas at pressure ranges that can adequately meet customer demand and the principles governing the operation of pressure regulation. A critical consideration is that operators must prioritize all efforts to preserve safe and reliable gas delivery, for the millions of customers being served by low-pressure systems. Operators of low-pressure systems know that widespread outages can occur quickly, if gas pressure is impacted by an outside event or by the unintended activation of a pressure or flow device.

Low-pressure systems continue to be a critical part of the natural gas industry in the United States. Although the industry continues its efforts to modernize the gas delivery infrastructure, there are unique challenges in replacing and upgrading low-pressure systems. We have experienced such obstacles as communities opposed to having gas utilities perform the work necessary to upgrade these systems to elevated pressure and customers who do not want to have their gas meters replaced/relocated. Operators typically need to install pressure regulator facilities and face limitations involving right-of-way considerations.

Low-pressure systems will continue to be a critical and necessary form of gas distribution for the foreseeable future; operators who have LP systems must continue to be provided the flexibility to manage the safety and reliability of these systems, within the framework of new regulations to ensure proper overpressure protection.

Learning from the Past to Mitigate Future Risk

What started as a pledge to improve our safety performance has become our way of working together, both internally within NGA and with our industry partners. Through the (NGA), members collaborate to share information and continuously learn in a group setting because we know it's our best pathway to meet the standard, we have set for ourselves and the public we serve. The tragic incident in the Merrimack Valley was a reflection point for our entire industry, particularly those that operate low-pressure distribution systems. In December of 2018, the NGA Board of Directors approved the creation of a Committee and API RP 1173 Pipeline Safety Management Systems (PSMS) Implementation Collaborative ("Implementation Collaborative") to specifically concentrate on embedding PSMS principles into day-to-day natural gas utility operations. These principles are at the very core and the intent of proposed rule changes addressed in this submittal.

The Committee's focus is on *operationalizing a safety management system strategy* by adopting a Plan-Do-Check-Act (PDCA) framework applicable to daily engineering, construction, operations, and maintenance activities. Our leaders' line of sight on how this approach drives down risk is an ongoing process. The Implementation Collaborative has grown significantly from a core complement of eleven Massachusetts based companies to a *movement* throughout the northeast and beyond; it is now over 18 organizations strong with over 30 operating organizations across the country including shared members of the American Gas Association ("AGA"), The American Public Gas Association ("APGA") and The Southern Gas Association ("SGA"). NGA's members are committed to applying these basic principles of continuous improvement *with every decision and every action,* with the goal of zero incidents.

Further, we have provided members with a collaborative environment to transform existing operating practices, behaviors and ultimately, safety culture, through implementation of applicable elements and principles in API 1173. The unique nature of the collaborative includes regional pipeline safety regulatory participation. PHMSA, along with our regional pipeline safety regulators is viewed as true pipeline safety partner. Several of our regional safety regulators are participating in development of PSMS engagement tools and technical guidance that addresses many aspects and intent of Congressional mandates in advance of this NPRM. In addition, our members have worked tirelessly, in a collaborative fashion, internally and with AGA in developing and implementing jurisdictional regulatory enhancements and industry guidance, policies and practices to ensure events of September 2018 never happen again.

These tools include:

- American Gas Association, AGA Technical Note "Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event"; November 26, 2018.

- American Gas Association, AGA White Paper “Skills and Experience for Effectively Designing Natural Gas Systems”; December 18, 2019. https://www.aga.org/research-policy/resource-library/skills-and-experience-for-effectively-designing-natural-gas-systems.
- American Gas Association, AGA White Paper “Natural Gas Utility Guideline for Developing a Management of Change (MOC) Plan for Engineering Design”; August 2021.

Building on these nationally recognized industry tools, NGA members further expanded principles highlighted in the aforementioned documents to specifically address regional aspects of pipeline system assets while further adopting a PSMS approach to risk mitigation. These PSMS focused guidance documents are included in the Appendix of this submittal for your reference and include:

- Northeast Gas Association, “Guideline for Gas System Engineering Design Review”, June 2020.
- Northeast Gas Association PSMS Implementation Collaborative, “Management of Change Applied to Local Distribution Companies PSMS Technical Guideline”, March 2022.
- Northeast Gas Association, “Guideline for Establishing & Maintaining Engineering Competency”, February 2023.

In summary, we can never forget the tragic nature of industry incidents that have brought us together in this journey to sustainably improve safety culture through adoption of PSMS fundamentals. The abovementioned industry tools directly address the intent of the NPRM and supplemental comments provided in this docket by NGA are intended to maximize public safety value while balancing the practical, technical, and logistical complexity of implementing sustainable improvements.

NGA supports initiatives that further enhance pipeline safety value including broader industry recognition and incorporation of operating practices that support managing and reducing operational risk while enhancing system reliability and ensuring integrity of the energy delivery network. NGA continues to work collaboratively with the AGA, APGA, jointly “the Associations”, in developing joint industry comments supported by a broad spectrum and experience of gas distribution system operators. NGA supports these comments and offers the following supplemental comments for consideration.

The comments submitted herein build upon the Associations comments focusing on proposed code sections that will have substantial regional Local Distribution Company (“LDC”) impacts for NGA members and as such, requires further clarification and/or revisions prior to adoption to achieve intended goals of maximizing public safety value.

General Comments:

1. Proposed Rule Effective Dates

NGA supports the Associations' belief that there will be unintended consequences resulting from the proposed implementation time-frame of twelve-months. NGA members continue to be actively engaged in voluntarily addressing lessons learned from the 2018 CMA Merrimack Valley overpressurization event, and in parallel, addressing recommendations provided in the September 29, 2020, PHMSA advisory bulletin (ADB–2020–02)[3], and elements of the PIPES Act. However, the proposals go beyond the scope of change operators are currently engaged in, as described in the Associations comments, to address what was presumed to be forthcoming in proposed rules and regulations as directed in provisions of the Pipes Act and NTSB recommendations.

The proposed changes are comprehensive, for example, requiring restructuring of emergency response plans, in coordination and working collaboratively with jurisdiction First Responders, formalizing specific management of change requirements and associated training and processes, DIMP enhancements, and design changes and upgrades for pressure regulation stations. In some regions of the country, particularly in the northeast where low-pressure distribution systems prevail, pressure control station enhancements prescribed in the NPRM number in the thousands, which is far greater than PHMSA's estimates. Securing materials due to continuing supply chain challenges, securing skilled resources, and evaluating each facility that may require enhancements, or in some cases complete replacement, will require thoughtful evaluation of timeframes to ensure operators can reasonably and safely meet these deadlines and extract the greatest degree of public safety value from these new requirements. Implementation timeframes need to consider an operator's ability to secure permits and integrate additional capital improvements within existing pipe replacement programs and other jurisdictionally approved capital improvement plans. In addition, challenges with implementation time-frames for this proposal must consider the compounding complexity of parallel and significant proposals included with the Gas Pipeline Leak Detection and Repair (LDAR) NPRM currently under review. The complexity of change management considerations for both proposals in aggregate with several jurisdictional pipeline safety and emissions monitoring regulations in the northeast region, recently enacted or in negotiation, cannot be underestimated[4].

---

[3] "Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems," ADB–2020–02, 85 FR 61097 (Sept. 29, 2020).

[4] NJ Rulemaking, N.J.A.C. 14:7-1.19 Effective June 5, 2023, CT Rulemaking, PURA 23-07-2, MA Rulemaking, DPU 22-100; Amend 220 CMR 100.00 and 101.00, NYSDEC Rule 203, Effective March 3, 2022, NYSDPS Case 19-G-0736 16 NYCRR Part 255 Effective March 18, 2022.

The scope of work required to meet the desired outcome of the proposed regulations is significant. These comments highlight implementation time-frames that are of concern and suggest practical alternatives that, for example, incorporate risk-based prioritization schedules such that the highest degree of pipeline safety value is realized as quickly as possible. Timeframes to implement certain aspects of this regulation, such as evaluation, retrofit and/or replacement of low-pressure system district regulator stations are very much dependent on a multitude of factors, which are explained in detail below.

First, the availability of qualified personnel, such as field personnel from the represented workforce, contractor personnel who conduct various construction or maintenance activities, or engineering personnel, including licensed professional engineers, will have a direct and profound impact on the ability of Operators to execute the work required by the proposed regulations. The current staffing levels of these skilled professionals are not sufficient to meet the demands of the proposed regulations given existing workload requirements. Expanding the workforce to enable Operators to execute the proposed work activities will take extensive time to recruit, hire, onboard, train, and qualify individuals as required by role. The scale of skilled and qualified individuals needed does not exist today in the northeast regional marketplace. Additionally, the need to review and amend the associated labor union agreements and contractor agreements would add to the time it would take to onboard the workforce required to execute work plans successfully and safely to meet proposed regulations.

Second, the impact of current facility design requirements, including the required review conducted by a licensed professional engineer in some northeast states[5], extends the time-frame needed to fully design much of the construction work required by the proposed regulations. Additionally, the current efforts required for facility siting, as well as municipal and state-level permitting, further increase the time-frame needed to execute this construction work. Furthermore, the global supply chain challenges continue to have significant impacts on the on the Operators ability to procure the necessary equipment and materials easily and speedily, particularly for specialty gas equipment, like relief devices and slam-shut valves, that again increases the time-frame needed for the work required by the proposed regulations.

Third, there are limitations that exist for each operator to execute the needed construction work within shortened time-frames due to seasonal constraints that ensure reliable service to customers. For example, the proposed regulations require Operators to conduct work at nearly all low-pressure district regulator stations across multiple northeast states, which in many cases requires taking these critical supply points out of service. To manage their gas distribution system safely and reliably, an Operator needs to properly coordinate any potential supply interruptions and limit these activities to the warmer months of the construction season, typically from April to November each year. Extra caution should be taken to ensure that proposed regulations do not introduce undue additional risks as a result of the short time-frames proposed.

[5] In Massachusetts, for example, as required by 220 CMR 105.

Finally, these timeframes are also highly dependent on the cooperation of municipalities to ensure timely work; municipal mark-outs, traffic control, in some cases mandated police details, and permit reviews among other tasks will all be necessary for NGA members to implement system changes stemming from these proposed regulations.

The safe and effective execution of a work plan to comply with these proposed regulatory changes requires reasonable implementation timeframes and operational flexibility, as each operator is impacted to varying degrees. There will likely be common initiatives that could be undertaken in a collaborative format (such as recommended risk-based studies) and there will also be numerous initiatives that are company-specific. While NGA members are committed to collaborating on certain studies and initiatives to allow for transparent implementation and efficient enforcement, timelines to implement company-specific components will vary depending on the scale of the company and their status/progress towards achieving the desired end state. Additionally, the recoverable costs required to comply with this regulation will include capital investments, incremental operation and maintenance costs, and associated contractor costs to continue on-going operations in compliance with revised regulations.

Like the LDAR proposal, NGA is supportive of a logical phase-in approach to the final rule with effective dates for different provisions within the rule based on the complexity and efforts required to comply with proposed changes in each Subpart. While some specific elements of the proposal may be implemented within 12 months, some Subparts warrant significantly longer time-frames based on the significance of the needed modifications to an Operators pressure regulation system assets and associated training, OQ, DIMP and O&M Plan enhancements, emergency response and communication protocols, data collection, reporting systems, procurement, jurisdictional rate agreements, etc.

Implementation time-frames will vary commensurate with the complexity and applicability to company specific assets and operations. Operators need sufficient time to develop meaningful change management plans that will provide a roadmap addressing final rule requirements such that change is sustainable and our parallel goals of enhanced public safety are achieved. NGA respectfully requests that the final rule feature effective dates that are practical and reasonable to facilitate sustainable change and to ensure a compliance glidepath that meets the intent of the proposal considering the complex changes that will likely occur in parallel with LDAR requirements. Operators are limited in commencing certain aspects of implementation efforts until they know the exact requirements of both Final Rule(s). NGA members have made significant safety improvements based on lessons learned from the CMA Merrimack Valley tragedy, including forming one of the largest LDC focused API RP 1173 Pipeline Safety Management System implementation collaboratives. Operators cannot speculate on how the requirements of both NPRM's will be modified throughout the rulemaking process and, therefore, cannot change procedures, operating policies or and design practices prior to final rules being in place.

While not desirable, at a minimum, NGA recommends a Stay of Enforcement be considered for more complex proposals for an appropriate period following final rule effective date(s) to allow Operators adequate time to perform asset specific assessments and develop implementation work plans that will maximize public safety benefits and ensure compliance. Operators would agree to develop and implement a risk-based regulator station improvement plan and NPRM Management of Change Compliance Workplan ("MOC Plan") within one year of the publication of the final rule. This will provide Operators to thoughtfully develop a plan that would include detailed analysis of organization specific impacts, training, OQ implications, O&M Plan revisions, DIMP plan revisions, contractual and supply chain considerations, database and other information technology systems, capital improvement plans in coordination with jurisdictional rate agreements and jurisdictional approved workplans currently underway. The proposed MOC Plan would be subject to jurisdictional regulatory review and in collaboration with PHMSA.

In summary, taking a *"one size fits all* " implementation approach does not address the operational impacts these sweeping changes, in combination with proposed LDAR changes, represent to our members. Considering specific operator asset variables such as the significance of low-pressure distribution systems in the northeast region, total population of legacy pipe materials identified for replacement, regulator system enhancements already underway and the associated regional complexity of executing work plans, permitting requirements, local jurisdictional resistance to allowing work on pipelines and state commissions re-thinking rate case recovery options due to policy decarbonization pressure, all need to be carefully integrated into each operator specific Distribution Rule MOC Plans.

2. Regulatory Overlap; Coordination and Consideration of Existing and Proposed Jurisdictional and Other Pipeline Safety Regulatory Change Proposals

NGA and our members are committed to working with policymakers in applying a *good science common sense approach* to eliminating overpressurization risk of low-pressure distribution systems and ensuring a layers-of-protection approach to design review and construction execution to minimize risk of unintended consequences.

NGA understands PHMSA's position to address aspects of the PIPES Act and the need to address safety regulations regarding overpressure protection of low-pressure systems. Regulatory change within the northeast region has understandably advanced ahead of federal proposals addressing both NTSB recommendations and PHMSA Advisory Bulletins resulting from the CMA Merrimack Valley incident. As identified above, over the past several years, jurisdictional regulatory advances have progressed within the northeast region that address the intent of Distribution Rule proposals including new regulatory requirements in Massachusetts, New York, New Jersey, and proposals currently under review in Connecticut and additional requirements proposed in Massachusetts. These jurisdictional changes impact a variety of NPRM proposals including pressure regulation and control design considerations, DIMP, leak detection and mitigation practices, training, Operator Qualification, MOC, design reviews, and emission reduction practices. While not identical to PHMSA proposals, work plans are being evaluated and/or implemented to ensure conformance with these requirements. NGA members feel it is essential for *alignment of intent* to maximize effectiveness of these changes, and where possible, provide flexibility in federal requirements to allow these changes already underway to be completed and achieve their intended purpose.

In summary, overly prescriptive federal regulation may have the unintended consequence of precluding conformance with jurisdiction change already planned or implemented compounding the complexity of the overall management of change process for both NPRM's.

Coordination and consideration of existing and proposed jurisdictional and other federal pipeline safety regulatory change proposals is essential to our parallel goal of extracting the greatest degree of pipeline safety value. There are many lessons to be learned from regulatory changes already negotiated and in place, as well as other regional efforts in progress, that should be evaluated and considered ahead of any final rule.

3. Notice of Proposed Rulemaking (NPRM) Code Section Discussion and Supplemental Comments

A. Distribution Integrity Management Programs (§192.1007)
B. Emergency Response Plans (§192.615)
C. Operations and Maintenance Manuals (Section §192.605) Overpressurization, Management of Change
D. Gas Distribution Recordkeeping Practices (Section §192.638)
E. Distribution Pipelines: Presence of Qualified Personnel (Sections §192.640)
F. District Regulator Stations—Protections Against Accidental Overpressurization of low-pressure regulators (Sections §§ 192.195 and 192.741)
G. Inspection: General (Section §192.305)
H. Records: Tests (Sections §§192.517 and 192.725)
I. Appendix – Supporting Documentation

A. Gas Distribution Pipeline Integrity Management (Subpart P)

NGA understands PHMSA is required to issue regulations ensuring that DIMP plans for gas distribution operators include an evaluation of certain risks, such as those posed by cast iron pipes and mains and low-pressure distribution systems, as well as the possibility of future accidents to better account for high-consequence but low-probability events. Gas distribution operators were required to make their DIMP plans, emergency response plans, and O&M manuals available to PHMSA or the relevant State regulatory agency no later than December 27, 2022.

Gas distribution operators must also make these documents, in updated form, available to PHMSA or the relevant State regulatory agency: (1) two years after the promulgation of regulations as required; and (2) every 5 years thereafter, as well as following any significant change to the document.

As with the Associations, NGA supports the notion that operators must revise their Distribution Integrity Management Programs (DIMP) in response to congressional mandates and NTSB recommendations, addressing lessons learned from the over-pressurization of a low-pressure distribution system incident in the Merrimack Valley. However, NGA is concerned with some of the proposed requirements in Part 192, Subpart P. NGA agrees with the Associations in that it is critical for PHMSA to promulgate regulations that:

- Are consistent with the original intent and fundamental essence of DIMP; “know one’s system”.
- Promote a performance-based approach in lieu of taking a “one size fits all” approach that is overly prescriptive.
- Do not unintendedly utilize DIMP as a regulatory “landing-place” for design/construction standards that PHMSA wishes to apply to existing facilities, in contravention of nonapplication clause 49 U.S.C. § 60104(b).

NGA believes that proposed revisions to Part 192, Subpart P may result in unintended consequences that could prevent it from being an effective and reasonable regulation. Underpinning DIMP is an Operators obligation to analyze their pipeline systems and identify threats to pipeline integrity and risk-rank relative importance. Operators are then required to take actions to address these risks. Operators must identify those risks on their pipeline where an accident could result in significant consequences, prioritize these risks, assess them periodically, repair identified anomalous conditions that meet specified criteria, and evaluate the results to validate that their programs to assure the integrity of their pipelines. Integrity management requires operators to use a risk-based approach to manage the safety of their pipelines based on intimate knowledge of their assets, operations and the environment in which operations are conducted.

NGA supports the Associations comments and respectively requests PHMSA consider the following clarifications in the final rule:

§ 192.1007 What are the required elements of an integrity management plan?

- *(b) Identify threats*

    - ✓ Consider language that includes *reasonable expectations* for defining extreme weather.
    - ✓ When referencing the age of materials of construction, consider using the term *vintage* as the exact age may not be known.
    - ✓ When referring to cast iron pipe, clarify the intent to address piping that *has not been rehabilitated,* enabling continued, safe utilization.

- *(c)(3) Low-Pressure Distribution Systems*

  ✓ Refer to low-pressure system *overpressurization* rather than describing the risk relative to non-jurisdictional equipment operation (appliance operation).

- *(d) Identify and implement measures to address risks.*

  ✓ NGA recommends PHMSA consider reasonable timeframes to complete low- pressure system record assessments and development of preventive and mitigative measures to minimize the potential for overpressurization. NGA believes based on the Associations assessments coupled with direct knowledge of low-pressure systems within the northeast region, that PHMSA estimates of LP system district regulator stations are significantly underestimated. NGA feels that the implementation timeframe for district regulator station enhancements does not reflect the disproportionate impacts to operators within the northeast region due to the nature of low-pressure systems in mature urban distribution networks. Some operators estimate a timeframe to complete this work as much as 20 years in balance with the number of stations requiring retrofits, the complexity of modifications within congested urban subsurface environments and a variety of system operating conditions that limit supply interruptions during periods of construction. As a result, in addition to the Associations revised estimates of national impacts, NGA polled northeast region operators to assess proposal impacts.

  For example, a single operator in New York has reported over 230 low-pressure district regulator station facilities of varying complexity and proposed rule conformance. Another regional operator reports in excess of 675 stations that require review and potential modifications, with both operators conducting business within complex jurisdictional construction and operating environments including New York City and the greater Boston areas. Yet another operator within the region reports over 1,200 low-pressure stations. Operators in the northeast region would have to complete these station upgrades in a shortened construction season to avoid operational and system reliability issues during cold winter temperatures. Additionally, Operators would be faced with qualified resource and logistical challenges to complete these station upgrades. For some operators, a retrofit or replacement glidepath of 15-20 years would be more reasonable, under certain conditions highlighted below, from a management of change, jurisdictional rate recovery and skilled resource/materials of construction availability perspective.

  As a result, NGA recommends PHMSA considers requiring each operator to conduct a detailed DIMP-based assessment of low-pressure system pressure control and OPP systems within 1 year from the publication of the rule.

> The assessment shall include a risk-based prioritization of low-pressure system retrofits and/or replacements to prevent overpressurization of low-pressure systems. The following parameters shall be considered in the assessment and mitigation plan:
> - Implementation plans and timelines for stations that have a full-capacity relief valve or slam-shut, but do not have 2nd-level OPP shall be updated to meet §192.195(c)(1) through (3).
> - Implementation plans and timelines for all other stations not meeting requirements of 192.195 (c)(1) through (3).
> - Consideration of timelines that include integration of station upgrades/replacements as part of jurisdictional pipe replacement/system upgrade plans approved by the authority having jurisdiction provided alternate measures are implemented to mitigate the risk of overpressurization as described in §192.195.

B. Emergency Response Plans §192.615

NGA understands PHMSA is required to update its emergency response plan regulations to address lessons learned from the CMA Merrimack Valley incident. Proposed updates are intended to ensure that each emergency response plan developed by a gas distribution system operator includes written procedures for how to handle communications with first responders, other relevant public officials, and the general public after certain significant pipeline emergencies (49 U.S.C. 60102(r)). Specifically, the updated regulations would ensure that pipeline operators contact first responders and public officials as soon as practicable *after they know* an unintended release of gas has resulted in a fire, an explosion, one or more fatalities, or the shutdown of gas service to a significant number of customers. Similarly, the updated regulations would provide for general public communication, *through an appropriate channel*, with general information regarding the emergency and status of the pipeline operations. In addition, requirements include the development of a voluntary opt-in system for rapid communication with customers.

In the NPRM, PHMSA also proposes four alternative emergency scenarios for §192.615(a)(3), two of which are linked to the Congressional mandate and the other two are a standalone new proposal related to pipeline ruptures, "notification of a potential rupture (see 192.635)."
Notification of a *potential rupture* does not constitute an emergency. It is worth noting that Section 203 of the PIPES Act specifically mandates that PHMSA update regulations to establish communication "as soon as practicable, beginning from the time of confirmed discovery [emphasis added]"[6]. The pipeline safety community has already contemplated the difference between notification of a potential emergency and the confirmed discovery of an emergency. This discussion led to the definition of *Confirmed Discovery* in §191.3,

NGA believes including §192.615(a)(3)(i) and (iv) in the required immediate notification requires clarification to meet intended benefits for operators and emergency officials.

[6] 49 U.S.C. 60102(r)(1) – "establishing communications with first responders and other relevant public officials, as soon as practicable, beginning from the time of confirmed discovery, as determined by the Secretary, by the operator of a gas pipeline emergency involving a release of gas from a distribution system of that operator that results in – "

Operators experiencing a hurricane, a natural disaster, for example, would not need emergency response unless a true emergency occurs *impacting a pipeline facility*. Likewise, an indication of gas detected near or within a building may or may not be an emergency.

There should not be an expectation to call a public safety answering point unless there is an actual confirmed emergency. In addition, these calls may overwhelm small call centers when there could be true emergency calls in the event of a hurricane or other natural disasters that are not actually impacting the pipeline system.

Lastly, NGA believes a customer opt-in/out notification system may not meet the intent of what the proposed rule change is attempting to provide in §192.615 (13). In a situation like the CMA Merrimack Valley incident, non-gas customers that are impacted by a potential gas emergency would not be within the operator customer database for notification. The most effective means to quickly disseminate an emergency notification to a geographic area would be through reverse-911 (works through older land-line phone connections and properly registered Voiceover IP phones); a community based opt-in messaging system that reverse-911 feeds into with the ability to include additional types of phones (i.e. cell); Wireless Emergency Alert (WEA), a State and Federal program that allows emergency notifications via cellular providers to wireless devices based upon affiliated cell phone towers in the vicinity designated by the alert initiator.

NGA supports the Associations comments and respectively requests PHMSA consider the following clarifications in the final rule:

- §192.615(a)(3) - Prompt and effective response to a notice of each type of emergency, including the following:

  (i) Gas *confirmed* inside or near a building that *in the judgement of the operator presents a public safety risk.*
  (ii) Fire *involving an unintended release of gas* involving a pipeline facility.
  (iv) Natural disaster *impacting a pipeline facility*
  (v) *Confirmed* discovery of a potential rupture (see § 192.635).
  (vi) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], release of gas from a *natural gas distribution system* that results in one or more fatalities.
  (vii) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], for distribution line operators only, unintentional release of gas and that results in a shutdown of a *gas main impacting 100 or more gas customer services* or if the operator has fewer than 100 *customer services*, 50 percent or more of its *total customer services interrupted.*

Finally, NGA respectfully requests PHMSA to recognize that while all states have an emergency management plan / systems in place, there may be a variety of secondary processes managed within each state specific system including variations in staffing and resource levels. As a result, regulatory change for gas system operators may have unforeseen secondary impacts on these state programs that will inevitably require state managed change beyond the control of the operator.

Each operator will need to work with emergency management officials within their respective jurisdictions to determine reasonable timeframes for execution of agreed upon process changes which may exceed the proposed 12-month timeframe.

C. Operation and Maintenance Manuals §192.605 – Overpressurization Events & Management of Change (MOC)

NGA understands PHMSA is required to update the regulations for O&M manuals to require distribution system operators to have a specific action plan to respond to overpressurization indications. Additionally, operators must develop written procedures for management of change (MOC) processes for significant technology, equipment, procedural, and organizational changes to their distribution system and ensure that relevant qualified personnel, such as an engineer with a professional engineer (PE) license or subject matter expert, reviews and certifies such changes.

- **Operation and Maintenance Manuals §192.605 – Overpressurization Events**

While NGA supports amending § 192.605 to address the response to a malfunction or operating error that causes an overpressurization *event*, it is important to recognize that operators have the responsibility to investigate and *verify indications leading to these events* and confirm that an overpressure event has occurred before taking the considerable step(s) of reducing pressure and/or shutting down portions of the gas distribution system. Prematurely isolating systems and taking actions without reasonable confirmation that an event is indicated may result in unintended consequences which could lead to system integrity issues that result in public safety risk.

For example, in complex urban distribution systems, prematurely isolating portions of the distribution system may result in large-scale customer interruptions and resulting complex service restoration efforts which may introduce additional pipeline and consumer safety risk. Section 204 of PIPES Act stipulates that for O&M manual requirements be revised to require written procedures for “responding to overpressurization indications, including specific actions and an order of operations for immediately reducing pressure in or shutting down portions of the gas distribution system, *if necessary*” (emphasis added). However, as-written, PHMSA’s proposed amendment to §192.605 does not include the “if necessary” qualifier, but instead suggests that operators must, in any scenario, reduce pressure or shut down portions of the distribution system immediately upon receiving an overpressurization indication before investigating and verifying the indication. NGA supports the Associations recommendations to amend the proposed language in §192.605(f) and offers the following clarifications for consideration:

- ✓ Procedures should be focused on specific actions associated with *overpressurization events not simply indications. Systems may experience* short term episodic pressure flucuations resulting from load swings and other routine operations that may be considered an "indication" however these situations are addressed immediately and are within the tolerance band of overpressurization design controls. As a result, to avoid unintended consequences of premature system isolation and unnecessary potential safety risks associated with restoration of service, an *event* in this context is more appropriate terminology to address the intent of the proposed regulation. While proposed procedures would address investigating an indication of potential overpressurization, actions such as controlled system isolation would occur if in the operator's opinion the indication is a confirmed event.

- **Operation and Maintenance Manuals §192.605 – Management of Change**

NGA supports the Associations contention that Section 204 of the PIPES Act is for PHMSA to promulgate a rule requiring a detailed procedure for Management of Change process. NGA, like the Associations, is confident the intent of Congress in requiring an MOC process was to provide controls that would prevent an event like the 2018 CMA Merrimack Valley incident. NGA believes Congress did not intend for PHMSA to impose a requirement for MOC to be universally applied to all gas distribution activities. Rather Congress intended for MOC to be applied in certain high-risk operational, design and construction execution functions. Further, MOC should be assessed in accordance with Pipeline Safety Management System principles outlined in API RP 1173, and as such, be scalable and applicable commensurate with the complexity of operations, design, and construction execution practices.

In addition, PHMSA is mandated by Congress to develop a rule requiring O&M manuals from distribution operators to "ensure relevant qualified personnel, such as an engineer with a professional engineer license, subject matter expert, or other employee who possesses the necessary knowledge, experience, and skills regarding natural gas systems, review and certify construction plans for accuracy, completeness & correctness." While the intent of this mandate is clear, to ensure *competency* of individuals reviewing and approving system design specifications, construction plans and operations & maintenance procedures, the reference to Operator Qualification (OQ) and Subpart N is misplaced.

While on the surface the OQ framework may seem like a logical solution to ensure design review competency, the OQ framework does not lend itself to the significantly different competency requirements of natural gas system engineering and design review.This is specifically noted in ASME B31Q in the discussion of a covered task. ASME B31Q stipulates:

With the following exceptions, this Standard applies to tasks that impact the safety or integrity of pipelines:

a) design or engineering tasks

The definition of a covered task does not encompass the broad scope of engineering functions. OQ is task and procedure oriented, and performance based. Engineering involves the application of a variety of design concepts and the strategic integration of these concepts and theory as related to constructability and operability of the design.

As a result, competency development and demonstration of engineering design review principles requires very broad knowledge and skills as well as system specific knowledge which often requires the technical review and input of multiple SMEs.

Given NTSB's recommendation following the CMA Merrimack Valley incident relative to the engineering plan and constructability review process, NGA membership including LDC engineering SMEs have developed fit-for-purpose guidelines for Gas System Engineering Design Review. The guideline (included in the appendix of this submittal) provides a framework for operators to define the education and experience requirements for engineering personnel, outlines the design review and approval process commensurate with design and constructability complexity for both standard (e.g., distribution mains and services) and non-standard (e.g., M&R stations and transmission facilities) facilities. The guideline also addresses competency requirements for those individuals engaged in design and construction drawings reviews, defines a management of change process, and includes practical design and construction review checklists based on asset types.
This guideline is intended to provide a flexible and scalable design and constructability review framework, with embedded elements of API RP 1173, Pipeline Safety Management Systems, and essential principles applicable to all pipeline operators, from large to small. This guideline is intended for operators to adopt essential elements and amend them accordingly based on their specific assets and unique operating environments.

NGA recommends that requirements for demonstrating competency associated with engineering functions and the engineering design review processes be excluded from references to Operator Qualification Subpart N requirements. Operators should consider the merits of a company-specific engineering design review process policy and procedure(s) developed describing the process and associated company-specific requirements in accordance with §192.605**.**

MOC involves a formal, resource-intensive process and needs to be applied in a fit-for-purpose manner to be effective proportional with the complexity of proposed changes. Directly following the CMA Merrimack Valley incident, NGA members worked collaboratively to develop several industry recognized guidance documents that address both a complexity-proportional process for implementing MOC and high-risk design review approval process. These documents were shared with both NTSB as well as Jurisdictional Regulators. Further NGA hosted an industry-wide Technical Workshop, which included PHMSA and NTSB participation to address the intent of NTSB recommendations and to introduce these guidelines for broader industry voluntary adoption. Copies of these Guidelines are included as references in the appendix of this submittal.

In summary, a one-size-fits-all approach to applying MOC across all aspects of distribution system operations is not only impracticable, but it may also result in unintended consequences of diluting the value of what change management is intended to protect. There must be defined criteria around the highest-risk work activities that warrant MOC, as with the alternative language provided in the Associations comments, supported by NGA. Clarifications in wording that would reasonably focus the application of MOC to to defined higher-risk activities. These activities include pressure control, processes to oversee change requests, changes in technology, personnel, equipment or procedures and specifications. Use of the word 'significant' is necessary to focus where MOC must be applied; higher risk activities which should be assessed by the operator. The operator is in the best position to determine what high-risk activities would benefit from the MOC.

process. In summary, the intent of legislation was to impose MOC requirements focused on high-risk activities such as design, operation, and maintenance of pressure control systems.

NGA supports the Associations recommendations to amend the proposed language in §192.605(g) and offers the following clarifications for consideration:

- ✓ Requirements should consider operators' assessment and identification of high-risk design and construction activities from both an engineering design and MOC process perspective.
- ✓ Focus any procedural requirements on *competency* of individuals and ability to recognize potential threats arising from 'significant' changes discussed above rather than *qualifications* to avoid the OQ Subpart N confusion.
- ✓ Avoid use of terms that create unintended confusion with Subpart N requirements, for example, use the term *functions* rather than *tasks.*

D. Gas Distribution Recordkeeping Practices (Section 192.638)

PHMSA proposes a new recordkeeping requirement for distribution system pressure control. This proposal is intended to address one portion of Section 206 of the PIPES Act resulting from an NTSB recommendation following the explosions and fires on September 13, 2018 in Merrimack Valley, MA. The NTSB recommended that NiSource "review and ensure all records and documentation of your natural gas systems are traceable, reliable, and complete."

The proposal requires operators of distribution systems to "identify and maintain traceable, verifiable, and complete records that document the characteristics of its pipeline system that are critical to ensuring proper pressure control." PHMSA proposes specific information that must be included in those records: location information for regulators, valves, and underground piping; attributes for the regulators (such as set points, design capacity, and valve failure position); the overpressure protection configuration; and other records deemed critical. PHMSA also proposes to require an operator to develop and implement procedures to address incomplete traceable, verifiable, and complete (TVC) records. The proposal specifically suggests that operators must address these incomplete records on an "opportunistic basis." The records must be maintained for the life of the pipeline and the operator must ensure the records are "accessible to all personnel responsible for performing or supervising design, construction, operations, and maintenance activities."

NGA agrees with the intent of PHMSA's proposal to address the Congressional mandate associated with documentation of pressure control equipment as this equipment plays a critical role in ensuring the continued safe operation of natural gas distribution systems. NGA supports the Associations recommendations that suggests some additional modifications to the proposed regulatory language to ensure that the goal of maximizing pipeline safety value is realized.

- ✓ PHMSA should maintain the standard of "Traceable, *Reliable*, and Complete" for these records.

  In §192.1007(a), PHMSA refers to §192.638 (c) and uses the term "traceable, verifiable, and complete." Similarly, 49 U.S.C. 60102(t)(1) requires PHMSA to require operators to identify and manage "traceable, *reliable*, and complete" records. PHMSA interprets "reliable" as used in 49 U.S.C. 60102(t)(1) to mean the same as "verifiable" as used in the 2019 rule because both verifiable and reliable would mean to prove that a record is trustworthy and authentic. In PHMSA's opinion, a record is considered reliable if it is verifiable and vice versa. The word reliable is defined as: "consistently good in quality or performance; able to be trusted." The word verifiable is defined as: "able to be checked or demonstrated to be true, accurate, or justified." Although similar, NGA shares the Associations concerns with PHMSA's assumption that these words are interchangeable and recommends the use of the word "reliable" vs. "verifiable" in this context.

- ✓ §192.638 (a)(4) – the operator with intimate knowledge of their pressure control systems is in the best position to establish other records of a critical nature. NGA suggests clarification and language such as *other records deemed critical by the operator*.

E. Distribution Pipelines: Presence of Qualified Personnel (Sections 192.640)

NGA supports the intent of the proposal to require an evaluation of overpressurization risk occurring at a district regulator station resulting from an operator's construction project activities. Conducting these "what if" type evaluations in advance of executing work associated with site specific job packages in the vicinity of a district regulator station provides the operator with advanced planning capability to avoid unintended consequences. Further, these risks and actions to be taken to mitigate consequences should be discussed in pre-job briefs prior to commencing work. These steps address core aspects of Safety Management System principles.

NGA supports the Associations recommendations to add §192.640 and offers the following clarifications for consideration to further enhance practical understanding and conformance with these requirements:

- ✓ 192.640(a) – NGA suggests clarification of potential risk of overpressurization related to operator construction work activities within a defined proximity to a district regulator station. NGA suggests that operator construction activities within a perimeter, or buffer zone, of 200 feet from a district regulator station, or if in the opinion of the operator overpressurization risk can be reasonably expected beyond this distance, the operator's approved construction project is subject to paragraphs (a) through(c) of this section.

- ✓ Construction projects/activity should be clarified as *operator* construction projects or activities.

- ✓ (b)(3) – An operator should have the flexibility of shutting off the gas flow off at the district regulator station or an alternate site identified by the operator, such as a single or series of line valves in the vicinity of the station.

F. District Regulator Stations—Protections Against Accidental Overpressurization (Sections 192.195 and 192.741)

PHMSA proposes to amend § 192.195 to require operators to equip all new, replaced, relocated, or otherwise changed district regulator stations serving low-pressure gas distribution systems with at least two methods of overpressure protection. PHMSA similarly proposes to amend § 192.1007(d)(2)(ii) to require operators to ensure two methods of overpressure protection are present – consistent with proposed amendments § 192.195 – at all *existing* district regulator stations serving low pressure distribution systems, or to identify (along with notification to PHMSA) alternative preventive and mitigative measures to minimize risk of overpressurization at these existing stations.

Additionally, PHMSA proposes to require operators to design each district regulator station serving a low pressure distribution system to minimize risk from an overpressurization of a low-pressure system caused by a single event (e.g., excavation damage, natural forces, equipment failure, or incorrect operations) that either immediately or over time affects the safe operation of more than one overpressure protection device. PHMSA furthermore proposes an amendment to § 192.741 that would require operators to provide monitoring of the outlet gas pressure at or near district regulator stations serving low-pressure systems (whenever these stations are new, replaced, relocated, or otherwise changed) using a device capable of real-time notification to the operator of overpressurization.

NGA supports the Associations comments and recommendations regarding proposals associated with §192.195 and §192.741 to district regulator stations and low-pressure distribution systems. NGA shares the Associations concerns with use of the term "otherwise changed," given the fact that many station enhancements unassociated with pressure regulation and control projects unintentionally meet the definition of "otherwise changed" as defined in GPTC as a "significant alteration". Changes involving alterations and reconfigurations of station ancillary equipment such as gas heaters, odorizers, filters and scrubbers should not be subject to design considerations specific to pressure control and monitoring. Moreover, PHMSA's proposed amendments to § 192.1007 already ensure that existing district regulator stations serving low-pressure distribution systems will be considered for, and/or retrofitted with, 2nd-level overpressure protection (or alternative preventive and mitigative measures to minimize risk of overpressurization). Consequently, the requirements proposed for § 192.195(c) should only be applied to new, replaced, or relocated district regulator stations serving low-pressure distribution systems. Requiring this within 192.195 will force operators to prioritize retrofitting overpressure protection at stations that are only scheduled for minor or unrelated modifications.

Additionally, while NGA supports PHMSA's proposal to require monitoring of pressure at or near district regulator station (serving a low pressure distribution system) overpressure protection devices (as per § 192.195(c)(3)), Section 206 of PIPES Act does not mandate that this pressure monitoring be performed *remotely*. Importantly, this proposal could result in unintended nullification of the exemptions to control room management requirements as defined in § 192.631(a)(1)(i). This exemption ensures that procedures for control room management, as defined by § 192.631, are not required for operators of small gas distribution systems (< 250,000 services). It is important to ensure that monitoring of a low-pressure distribution system does not undo this exemption, by virtue of the fact that "part of a pipeline facility" is being "monitored…through a SCADA system." Therefore NGA, as with the Associations, propose that gas distribution systems that meet the exemption for control room management procedures (as defined in § 192.631(a)(1)(i)) also be exempt from the requirement that pressure monitoring be performed remotely.

NGA agrees with the Associations that PHMSA's proposal to revise § 192.741 to require pressure monitoring (in accordance with § 192.195(c)) on "low-pressure distribution systems that are new, replaced, relocated, or otherwise changed" is superfluous to § 192.195(c) itself. In the exceedingly unlikely event that a gas distribution pipeline operator would install a *new* low-pressure distribution system, replace such a system with *another* low-pressure system, or relocate a low-pressure system in its entirety, the operator would almost certainly build, replace, or relocate the district regulator station(s) feeding that system, thus ensuring that pressure monitoring would be provided as per § 192.195(c). In contrast, "otherwise changing" low-pressure distribution systems (as opposed to the district regulator station that serves them) whereby the system *remains* low-pressure, might occur at such a frequency, and (as stated previously) with such irrelevance to controlling the pressure of the system, that mandating the installation of pressure monitoring for every such project would be both onerous and of limited safety value. In any case, § 192.195(c) already fulfills the mandate of Section 206 of PIPES Act, which requires that "each operator of a distribution system [assess] and [upgrade], as appropriate, each district regulator station of the operator to ensure that….the gas pressure of a low-pressure distribution system is monitored,particularly at or near the location of critical pressure-control equipment."

While the NGA and the Associations recognize the potential risk of replacing a low-pressure distribution system with a new, high-pressure distribution system (as was the case for the CMA Merrimack Valley incident), those particular risks are addressed and controlled for in the other provisions of this NPRM. As a result, NGA supports the Associations recommendation that the newly proposed § 192.741(d) be struck.

NGA recognizes measures, such as the installation of 2nd-level overpressure protection and monitoring of gas pressure, are effective in providing additional protection against overpressurization of low-pressure gas distribution systems; it is critical to recognize that alternative preventive and mitigative (P&M) measures can provide equivalent levels of protection against overpressurization[7]. NGA, like the Associations appreciates PHMSA's recognition of the potential effectiveness of these alternative P&M measures in their proposed requirement to evaluate and/or upgrade existing district regulator stations (see § 192.1007(d)(2)(ii)(B)). However, these alternatives should also be available for new, replaced, and relocated district regulator stations serving low-pressure distribution systems. Indeed, Section 206 of PIPES Act 2020 requires that district regulator stations be "assess[ed] and upgrade[ed], as appropriate," and furthermore that alternative "actions…that minimize the risk of an overpressurization event" may be identified by an operator if the more prescriptive requirements (proposed in § 192.195(c)) are not operationally possible. Some operators have already made significant investments in assessing and modifying their district regulator stations and low-pressure distribution systems to protect against the risk of overpressurization that conforms with the intent of Congressional mandates.

[7] AGA White Paper, Leading Practices to Reduce the Possibility of a Natural Gas Over-Pressurization Event, November 26, 2018

As a result, operators should be given flexibility to identify alternative P&M measures for minimizing the risk of overpressurization on new, replaced, and relocated district regulator stations serving low-pressure distribution systems. Preserving this flexibility in § 192.195 would allow and encourage implementation of technologies such as automated detection of damaged/ compromised pressure control lines (i.e., putting pressure regulation and overpressure protection into passive operation), meter technology with overpressure protection and excess flow functionality, and other state-of-the-art technologies.

Finally, within this NPRM, PHMSA acknowledges that work on facilities involving pressure control and overpressure protection devices poses a unique risk, requiring, among other things, management of change (§192.605), on-site presence of qualified personnel (§§192.605 and 192.640), implementation of emergency response plans (§192.615), and record collection (§192.638). Initiating such work therefore introduces risk of the very overpressurization events that this NPRM seeks to prevent and mitigate. This is particularly concerning when this work is being proposed on an unprecedented scale, with disproportional impacts to NGA members in the northeast region due to the nature of existing operations (thousands of district regulator stations serving low-pressure distribution systems) and either concurrently with, or more probably *prior to*, completing implementation of the enhanced management of change, personnel qualification, emergency response plans, and record collection procedures proposed in this rulemaking. Compressing this work into one year is a further risk multiplier, and a significant one at that. In short, the requirements and timeline proposed by PHMSA in §192.1007(d)(2)(ii) is not only unlikely to decrease the risk of overpressurization of low-pressure distribution systems, it stands to unintentionally and significantly *increase* this risk.

As described in comments regarding proposed rule effective dates, and more specifically in comments provided in §192.1007, coupled with the aforementioned reasons, NGA recommends that each operator be required to conduct formal asset assessments and develop implementation plans and timelines (or identify alternative P&M measures for mitigating risk of overpressurization) within 12 months of rule publication. These plans would consider the following parameters in proposing timelines that will be reviewed and approved by the authority having jurisdiction including the following parameters:

- Implementation plans and timelines for stations that have a full-capacity relief valve or slam-shut, but do not have 2nd-level OPP shall be updated to meet §192.195(c)(1) through (3).
- Implementation plans and timelines for all other stations not meeting requirements of 192.195.
- Consideration of timelines that include integration of station upgrades/replacements as part of jurisdictional pipe replacement/system upgrade plans approved by the authority having jurisdiction provided alternate measures are implemented to mitigate the risk of overpressurization as described in §192.195.

This risk-based approach to an implementation timeline would also allow for the upgrading of district regulator stations (or implementation of alternative P&M measures to guard against low-pressure system overpressurization) to be done prudently and intentionally considering planned pipeline replacement projects.

NGA supports the Associations recommendations to amend the proposed language in §192.195 and §192.741 and offers the following clarifications for consideration:

§192.195 Protection against accidental overpressuring.

- ✓ (1)(i) - Further clarification, at least two *means* of overpressure protection (such as, *but not limited to,* a relief valve, monitoring regulator, or automatic shutoff valve) appropriate for the configuration and siting of the station.
- ✓ (c) – Eliminate or further clarify the reference to *otherwise changed* to identify any *significant modifications or changes that could impact overpressurization risk within a low-pressure distribution system*.
- ✓ (3)(iii) Clarify remote monitoring is required *unless* the operator is exempted from control room management requirements as per § 192.631(a)(1)(i).
- ✓ Provide option and resulting additional operational flexibility for an operator to identify alternative site-specific preventive and mitigative (P&M) measures and risk-based implementation timeframes based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system.

§192.741 Pressure limiting and regulating stations: Telemetering or recording gauges

- ✓ Address the need to recognize recording gauges, telemetering *and other monitoring devices* are acceptable as some small operators are exempt from control room management requirements as per § 192.631(a)(1)(i) (see §192.195(c) above).
- ✓ (d) Similar to recommendation §192.195(c) above, Eliminate or further clarify the reference to otherwise changed to identify any significant modifications or changes that could impact overpressurization risk within a low-pressure distribution system.

G. Inspection: General (Section 192.305)

NGA recognizes the historical significance associated with §192.305. In summary, in the 2015 PHMSA "Miscellaneous Changes to Pipeline Safety" rulemaking[8] PHMSA modified §192.305 to address a 2002 National Association of Pipeline Safety Representatives (NAPSR) Petition for Rulemaking. That NAPSR petition requested that PHMSA amend the regulation to "prohibit a contractor that is hired to do construction work for an operator from inspecting its own work."[9] After the final rule, both NAPSR and APGA filed petitions for clarification or reconsideration. APGA requested that PHMSA clarify that PHMSA was "not intending to require third party inspections or attempting to prohibit any person from a company to inspect the work of another

[8] Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations. Final Rule. 80 Fed. Reg. 12,762. https://www.federalregister.gov/documents/2015/03/11/2015-04440/pipeline-safety-miscellaneous-changes-to-pipeline-safety-regulations
[9] NAPSR Central Region Resolution. Resolution CR-1-02. May 9, 2022.

person from the same company".[10] NAPSR petitioned PHMSA to reconsider the amendment to §192.305 and revise it to address their concerns, specifically allowing contract personnel to inspect the work of their crews if the inspector did not directly perform the task being inspected, appears to apply to operator construction personnel as well, and significantly limits the scope of inspection requirements by limiting required construction inspections of mains and transmission lines to only requirements found in Subpart G, rather than in all of Part 192.[11] On September 30, 2015 PHMSA issued a response to the NAPSR and APGA petitions and delayed the effective date of the amended §192.305 indefinitely.

In the Safety of Gas Distribution Pipelines NPRM, PHMSA proposes to address the APGA Petition for Reconsideration by adding §192.305(b), in which it is NGA's understanding that an operator is permitted to inspect the work associated with this subpart performed by their crews provided the inspector did not perform the task being inspected.

While the NGA supports the Associations recommendations that *PHMSA must first address all remaining questions and confusion that resulted from their first introduction of this provision, before attempting to enforce this requirement,* NGA reemphasizes it's understanding of the intent of §192.305 and offers the following minimum clarifications for consideration:

- ✓ (a) Further clarification that an operator is permitted to inspect the work conducted in accordance with this subpart provided the personnel performing the inspection did not perform the physical work associated with the task being inspected except as provided in (b).
- ✓ Allow for the use of technology based remote inspections.

H. Records: Tests (Sections §192.517, and §192.725)

PHMSA proposes to modify § 192.517(b) to prescribe attributes of the test record that must be maintained and require test records to be retained for the life of the pipeline. This proposal is in response to a 2021 National Association of Pipeline Safety Representatives (NAPSR) Resolution. NAPSR requested that PHMSA (1) modify 49 CFR § 192.517(b) to require that documentation be retained for the life of the pipeline, including test pressure documentation created within the five years prior to the effective date of the rule change and (2) additionally modify § 192.517(b) to require specific test attributes. PHMSA also proposes to modify § 192.725 – *Test requirements for reinstating service lines* to align the record retention requirement with the proposal for § 192.517(b).

However NGA is concerned that the NPRM suggests record retention periods that add little or no safety value and content details and retention requirements that may not add the safety value presumed in the current proposal. Furthermore, the proposal fails to recognize fundamental differences in the purpose of a leak test verses a pressure strenght test and the associated safety benefits in making this distinction.

[10] 80 Fed. Reg. at 12764
[11] NAPSR Request for Delay in the Effective Date of Amended Rule 192.305 on Construction Inspection. July 28, 2015.

Regarding record retention, for example, the Plastic Pipeline Database Committee (PPDC)[12] reviews and reports on failures within plastic pipeline systems across the United States. Experience from within the PPDC shows that failures due to installation error typically happen within the first 5 years, and later life failures are typically due to material degradation. This demonstrates that any failures due to improper pressure testing would be expected to happen early in the life of the pipeline, and keeping records *for the life of the pipeline* only increases administrative costs and does little to improve safety.

Leak tests and pressure strength tests are not synonymous and their purpose in ensuring safe operations of pipelines differ. NAPSR's 2021 petition for rulemaking points to PHMSA's record retention requirements for pressure test records in §192.517(a) as justification for additional requirements in §192.517(b). §192.517(a) specifies recordkeeping for the various testing requirements of steel pipelines, §§192.505, 192.506, and 192.507. §§192.505 and 192.506 both detail strength testing requirements for transmission lines and higher-pressure distribution steel pipelines. §192.505 is intended to substantiate the proposed MAOP of a new pipeline, and §192.506 is intended to evaluate additional threats on a new or existing pipeline, where the operator deems it to be necessary. §192.507 is also intended for non-plastic pipelines operating at pressures at or above 100 PSI, but with the intended purpose to discover leaks.

In contrast, §192.517(b) specifies recordkeeping requirements for tests on low to medium pressure pipelines, service lines, and plastic pipelines. The purpose of these tests is to identify all potentially hazardous leaks in the segment being tested prior to installation. This testing is consistent with recommendations under ASME B31.8, which also explicitly differentiates between pressure testing of distribution pipelines and service lines to *discover leaks* versus *strength testing* of transmission and high-pressure distribution lines to discover and repair various potential defects on those higher risk pipeline segments.

Furthermore, The Plastic Pipe Institute (PPI) states that, "Leak tests of pressure systems generally involve filling the system or a section of the system with a liquid or gaseous fluid and applying internal pressure to determine *resistance to leakage.*" [13] Resistance to leakage is separate and different from verification of the strength of the pipe material. In fact, every time a natural gas distribution operator performs a leak survey on a pipeline system (per §192.723), the operator is effectively performing a new leak test.

NGA agrees with comments of the Associations supporting clarification of the recordkeeping requirements for §§192.509, 192.511 and §192.513, and retaining leak test records should align with current DIMP record retention requirements, which is 10 years.

Furthermore, information included in the test records should align with the information needed for verification for the safe operation of the pipeline. As discussed above, leak tests are performed on low or medium pressure pipelines at the time of construction to verify no hazardous leaks exist on the pipeline when the pipeline is put into service. Therefore, the only information essential for the test record is identification of the pipe segment being tested, the date of the test, and the test pressure.

[12] The Plastic Pipe Database Committee (PPDC) is a group of representatives of federal and state regulatory agencies and the natural gas and plastic pipe industries. The goal is to create a national database of information related to the in-service performance of plastic piping materials. https://www.aga.org/natural-gas/safety/promoting-safety/plastic-pipe-data-collection-initiative/
[13] https://www.plasticpipe.org/MunicipalAdvisoryBoard/MunicipalAdvisoryBoard/Navigation/Connection-Menu/Pressure-Testing.aspx#:~:text=Leak%20tests%20of%20pressure%20systems,to%20determine%20resistance%20to%20leakage.

NGA believes while many operators elect to document varying levels of detail on test records, the regulatory requirements should address essential record elements. Operators should specify company specific requirements of documentation records, which should include at a minimum, the stated essential record elements cited above. Finally, NGA agrees with the Associations comments in that PHMSA's proposed revisions to §192.517(b) are confusing and could be easily misinterpreted. PHMSA's proposed regulatory changes includes a modification to 192.517(b) to state that all test records are to be maintained for the "life of the pipe". This is confusing and is likely to result in future misunderstandings. To avoid misunderstandings and add additional clarification, NGA supports the Associations suggested revisions to 192.517 for the three different scenarios under consideration:

1. Tests that occurred more than five years prior to the publication of a final rule.
2. Tests that occurred within five years prior to the publication of the final rule.
3. Tests that occurred on or after the publication of the final rule.

In summary, NGA supports the Associations recommended enhancements to the proposed test record regulatory language.

NGA appreciates the opportunity to provide comments in this matter.

Respectfully submitted,

Jose Costa

By: Jose Costa
President & CEO
Northeast Gas Association
1800 West Park Drive,
Ste 340, Westborough, MA, 01581
jcosta@northeastgas.org

For further information please contact:

Paul Armstrong
Vice President of Operations
Northeast Gas Association
(781) 455-6800 ext. 1130
parmstrong@northeastgas.org

or

Robert Wilson
Vice President Special Projects
Northeast Gas Association
(607) 643-5111
bwilson@northeastgas.org

APPENDIX

Appendix A - Guideline for Gas System Engineering Design Review, Northeast Gas Association, June 2020.

Appendix B - Management of Change Applied to Local Distribution Companies PSMS Technical Guideline, Northeast Gas Association PSMS Implementation Collaborative, March 2022.

Appendix C - Guideline for Establishing & Maintaining Engineering Competency, Northeast Gas Association, February 2023.

Appendix A - Guideline for Gas System Engineering Design Review, Northeast Gas Association, June 2020.

Northeast GAS ASSOCIATION

Guideline for Gas System Engineering Design Review

Foreword

This Guideline was developed by members of the Northeast Gas Association (NGA) and is intended to provide NGA Pipeline Operators with a framework and considerations for developing and enhancing an organization-specific gas system engineering design review (EDR) process. The goal of implementing a gas system design review process is to ensure that gas transmission and distribution systems are designed, constructed and operated in a safe and reliable manner with the goal of zero incidents. Engineering design reviews as applied to natural gas system assets and operations can range from:

- Standard designs, application of standard designs, or simple changes to standard designs, to;
- Complex, non-standard designs that include many linked stakeholders and subject matter experts (SME's) within an organization.

Regardless of design complexity, organization size or scale of assets being managed, each organization should have a design review process in place that ensures appropriate review of essential elements of design with a focus on pipeline and process safety, constructability and operability. The design, as well as the design review, must be conducted by competent person(s) familiar with the specific subject matter commensurate with the complexity of the project. The scope of this document includes gas transmission and distribution pipelines, systems and appurtenances.

The Northeast Gas Association (NGA) is a regional trade association that focuses on education and training, technology research and development, operations, planning and increasing public awareness of natural gas including natural gas pipeline safety within the Northeast region of the U.S. The Northeast Gas Association represents gas distribution companies, transmission companies, liquefied and compressed natural gas suppliers and associate member companies. NGA member companies provide natural gas service to over 13 million customers in 9 states (CT, MA, ME, NH, NJ, NY, PA, RI, VT).

NGA publications are developed by membership committees and are intended to facilitate sharing of broad, proven, sound engineering and operating practices. Publications may be used by any member desiring to do so. Every effort has been made by the NGA to assure the accuracy and reliability of the data contained in them; however, the NGA makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

Acknowledgement

The Northeast Gas Association would like to acknowledge members that participated in the development, review and approval of the Engineering Design Review Guideline. In addition, NGA would like to acknowledge the Blacksmith Group for their support in development and review of the Guideline to ensure conformance with pipeline safety management system principles.

Central Hudson Gas & Electric Corp.

Columbia Gas of Massachusetts

Columbia Gas of Pennsylvania

Connecticut Natural Gas

Consolidated Edison Company of New York

Corning Natural Gas Corporation

Elizabethtown Gas Company

Eversource Energy

Iroquois Gas Transmission System

Iroquois Pipeline Operating Company

Liberty Utilities

National Fuel Gas Distribution Corporation

National Grid

New Jersey Natural Gas Company

New York State Electric and Gas

Norwich Public Utilities

Orange & Rockland Utilities, Inc.

PECO Energy

Philadelphia Gas Works

Public Service Electric & Gas Company

Rochester Gas & Electric

South Jersey Gas Company

Southern Connecticut Gas

Summit Natural Gas of Maine

UGI Utilities, Inc

Unitil Gas & Electric Light Company

Vermont Gas Systems Inc.

Guideline for Gas System Engineering Design Review

1. Purpose

2. Leadership Commitment and Stakeholder Engagement

3. Essential Elements of Gas Engineering Design Review

3.1 The Gas Engineering Design Review Process

3.2 Core Principles of Design Review

3.3 Typical Roles and Responsibilities

- Engineering Executive
- Chief Engineer/Engineering Director
- Technical Expert/Professional Engineer with Gas System Design Experience
- Engineering Supervisor/Manager
- Design Engineers / Competent Person(s)

4. Training, Education, and Experience of Competent Person(s)

4.1 Professional Engineer or Equivalent Technical

4.2 Gas Distribution Engineering

4.3 Gas Transmission Engineering

4.4 Gas Processing Engineering

5. Standard Engineering Designs

5.1 Defining Standard Engineering Design Activities

5.2 Review and Approval of Standard Engineering Design/Construction Practices

6. Complex and Non-Standard Engineering Designs

6.1 Defining Complex and Non-Standard Design Activities

6.2 Review and Approval of Complex, Non-Standard Designs and Construction Practices

7. Management of Change Policy / Operational Controls

8. Safety Assurance

APPENDIX

1. Purpose:

The Northeast Gas Association provides this Engineering Design Review (EDR) Guideline to help operators enhance risk management practices and safety assurance through a strategy of added layers of protection and *defense in depth* throughout the design, construction and inspection review process. The process considerations provided in this document are intended to guide operators in how to determine which parties need to be included in EDR and ensure decisions are vetted appropriately. This process will provide added visibility to the accountability of all individuals involved. Documentation of the steps undertaken through the process will enable transparency. Inclusiveness of all parties who can contribute knowledge and competence results in a broader multidisciplinary and well-rounded perspective on actions that need to be taken. Providing a record of approval by a company specific level of authority, commensurate with the complexity of design, is an added level of assurance that leadership attests to the completeness of the steps undertaken as identified by the operators' written procedures.

EDR, as applied to natural gas system construction (including pipeline abandonment) and operations, is an evaluation process that is a fundamental component of risk management. In some cases, the process is independent of the original design engineer, in which a competent person(s) assesses a project design for conformance with relevant local, state and federal construction codes and permit requirements, pipeline safety regulations, and an operator's specific policies relative to Pipeline Safety Management System (PSMS) requirements, operation and maintenance procedures, construction practices and standard drawings. In addition, the review process may include assessing conformance with the recommended application of specific materials of construction, device(s) and recommended installation practices or requirements by material, equipment and device manufacturers. The design review process also considers and evaluates risks in the process, and specifically, steps to reduce risk by the materials specified, construction and abandonment techniques as well as operational requirements such as management of pressure.

An EDR process also includes elements of constructability and operability where appropriate, depending on complexity. For example, the design review will evaluate the construction methods selected and ensure they are appropriate for the location where the work is to be conducted. Factors such as proximity to other utility infrastructure, surface conditions (e.g. roads, pavement, streams, trees, wetlands, etc.), in the path of mains and service installations, traffic control, and terrain are considered. The EDR will also integrate elements of final as-built construction inspection checklists, pre-startup safety reviews (PSSR) and System Operating Procedures (SOPs). This includes assessing the need for obtaining operational clearance (permission to work) from gas control prior to energizing or deenergizing a pipeline segment. Assessing and implementing these "safety gates" associated with the commissioning and/or decommissioning of facilities associated with the project design implementation are an integral component of the end-to-end safety-in-design review process.

This Guideline provides EDR considerations and guidance for NGA membership associated with development of organization specific EDR process procedures. The scope of this document includes qualification and competency considerations of individuals conducting EDRs, defining essential elements of the EDR process, management of change, continuous improvement, documentation practices and PSSR, as an integral component of design review and constructability/operability considerations.

The Guideline also includes sample Design, Construction and PSSR checklists for pipeline operators to consider when developing organization specific gas system EDR process procedures and checklists.

This Guideline incorporates essential elements and concepts, where applicable, included in Pipeline Safety Management Systems API RP 1173. Some of these core elements include:

- Risk Management;
- Leadership and Management Commitment;
- Safety Assurance;
- Stakeholder Engagement;
- Operational Controls;
- Competency, Awareness and Training;
- Management Review and Continuous Improvement;
- Documentation and Recordkeeping;
- Incident Investigations, Evaluations and Lessons Learned.

In summary, this Guideline is intended to provide a consistent framework and essential elements of the design review process for pipeline operators to consider in developing their organization specific gas EDR process. While essential principles of EDR are applicable to all pipeline operators, large to small; this Guideline is intended to be flexible and scalable depending on the complexity and size of an operator's assets. This Guideline is not intended to supersede local, state or federal license requirements for conducting EDRs.

2. Leadership/Management Commitment and Stakeholder Engagement

Leadership within the operator's organization must make a clear commitment to ensuring appropriate layers of protection are in place within the gas EDR process and establish a monitoring plan. It is important to explain that to take safety performance to the next level, the organization needs to be inclusive of parties which need to be involved in the process, either because they are affected by the work or have knowledge and experience to contribute in identifying and managing design risk factors. This commitment also includes:

- Strengthening the process and improving information flow from front line staff who can identify potential problem areas;
- Encouraging the involvement of employees regardless of position to make recommendations and contribute to decisions;
- Placing a priority on how to get all employees thinking about consequence issues and institutionalizing improvements for consistent application;
- Assuring that in the management review process there are appropriate levels of cross check redundancy in the layers of protection and that interfaces are occurring between departments who need to exchange information;
- Assuring that Management of Change (MOC) is in place and evaluated. Determine if events are monitored, if lessons learned are identified, and corrective actions are taken;
- Committing to establish an audit plan for the gas EDR process on a priority basis.

3. Essential Elements of Gas Engineering Design Review

3.1 The Gas Engineering Design Review Process

Gas EDR is an objective evaluation process that in some cases is independent of the original design engineer/engineering team, in which a competent person(s) assesses core elements of a gas system engineering design (piping systems, gas pressure/flow control facilities, gas processing systems and other facilities and equipment). An engineering design review should be considered a continuous process beginning with the design engineer, internal/external design approvals, construction and final inspection and commissioning of the facility. Knowing someone else in the process will check design work is no excuse for not self- checking each step. The scope and extent of the review process is dependent on the complexity of the procedure, design, construction project or proposed change to an approved procedure, design or project.

For purposes of this document, competent person(s) is defined as a person(s) having appropriate levels of education commensurate with the complexity of the project and/or having demonstrated practical field experience (such as with engineering construction, operational, and regulatory knowledge of the specific subject matter being designed or reviewed). In addition, a competent person would have knowledge of specific and relevant gas system assets to ensure that the application of the design in practical terms does not result in unintended operational consequences that affect safety or reliability of the system. A competent person(s) may be individual(s) within the organization or a designated third party independent of the project.

For distribution system operations, the EDR process typically falls within three sub-processes: Standards, Procedures and Work Practices (including operational enhancements to existing systems, procedures or designs); Standard Designs for Site Specific Projects; and Site/ Project Specific Complex, Non-Standard Designs.

1. Standards, Procedures and Work Practices play an important role in gas system design and operations. These design standards enable consistency in design, construction, operations and maintenance and help ensure compliance and pipeline safety. The EDR process for Standards, Procedures and Work Practices includes a structured approach to review by individuals directly accountable for performing work in accordance with these documents. This would be followed by Standards & Procedures Supervisor/Manager/Technical Expert approval and in some cases, approval by the Chief Engineer, Engineering Director and/or Operations Director. In some organizations, standard construction designs/drawings are incorporated into these documents and follow an integrated design, policy, procedure approval like that described below for Standard Designs. In other cases, "enabling" construction procedures or operating procedures that must be carried out as part of construction*,* (i.e. purging, tie-in's, etc.) are incorporated into the project specific design review process. A sample review and approval process flow for work methods, procedures, standards & policies is included in Appendix 1.

2. Application of Standard Designs to Site Specific Projects incorporate approved construction standards, specifications, drawings and/or procedures that have gone through a prior EDR process in accordance with an operator's specific policies such as simple mains and services design. These designs typically have a "review gate" process with two to three layers of review starting with the design engineer and associated project SME's (from other related functional areas of the organization such as operations, construction, regulatory, safety, etc.), coupled with a final review by an Engineering Supervisor/Manager, and, in some unique/select cases, for more complex standard project designs, the Engineering Director/Executive. A sample process flow is included in Appendix 2.

As an example, standard project designs include:

- Simple main installation, renewal, replacement, abandonment;
- Simple service installation, renewal, replacement, abandonment;
- Non-complex new valve installation or replacement (not requiring a by-pass); or
- Simple customer meter/regulator installation or replacement.

3. Site/Project Specific, Complex, Non-standard Designs include complex designs or modifications to standard designs *that are not addressed in an operator's specific standard designs, operating procedures, and/or standard construction drawings.* The EDR process for complex, non-standard designs may include an additional review gate by a competent person, independent of the original design team. While most reviews can be effectively conducted by appropriate internal competent personnel, in some specific cases, complex, non-standard EDRs may warrant review by an independent, competent third party. A third party may include a Licensed Professional Engineer (PE) or equivalent Technical Expert with gas engineering design and operating experience commensurate with the complexity of the project.

As an example, non-standard complex EDRs may include:

- Design and construction of new or reconfigured district pressure regulator or custody transfer facility including pressure/flow control and safety monitoring systems beyond the scope of a simple, pressure control standard design;
- Pipeline construction and maintenance activity in the vicinity of a pressure regulator station as defined by an organization's policy or procedure;
- Uprating of intrastate transmission or distribution pipelines outside of the scope of routine uprate projects defined in an organization's standard policy or procedure;
- Gas transmission and/or distribution complex construction/abandonment such as projects incorporating multiple standard design options which in aggregate result in a potential high-risk complex project;
- Design and construction of compressor stations and gas processing facilities.

A sample process flow is included in Appendix 3.

3.2 Core Principles of Design Review

Personnel responsible for design-construction may include appropriate engineering and operations departments, engineering professionals (PE or equivalent technical experts), consultants and contractors. Participants in the design-construction process have individual responsibilities and obligations that are in many cases integrated and interrelated commensurate with the scope and complexity of the design. Regardless of complexity, design review begins with the project design engineer as each designer is responsible for his/her own work. The desired outcome of the EDR process is to ensure any design affecting the gas system minimizes system operational risk while maximizing public safety value. To achieve this goal, EDR must be carried out using an operator approved process that's inclusive of all appropriate stakeholders. Stakeholders are those individuals that may be affected by the work incorporated within an individual design or who have knowledge or experience to contribute which might not be otherwise included.

An operator's specific EDR process policy should be fit-for-purpose relative to project complexity and consider the following elements[3]:

[1] Internal competent personnel may include a Professional Engineer with gas system design experience or an equivalent Technical Expert with experience, commensurate with the complexity and scope of work.

[2] Third party PE must be experienced in gas EDR commensurate with the complexity of the project.
[3] Incorporated from Design Review Principle and Practice, 2013, The Design Council, Royal Institute of British Architects

1. **Independent (Complex, Non-Standard Designs)** – where specified in an operator's specific policy, is conducted by an individual(s) not directly involved with the project and ensures no conflicts of interest. If specified in an operator's policy, the independent party performing the EDR may be an employee or a third-party firm.

2. **Expert** – It is carried out by suitably trained individual(s) who is experienced in gas system design and operations. The individual(s) must possess the ability to comment constructively from the standpoints of constructability, operations, pressure control and work site safety.

3. **Objective** – the review focuses on core engineering principles, conformance with the operator's specific standards and procedures, local, state and federal codes and industry standards.

4. **Multidisciplinary** – It combines perspectives from subject matter experts (SMEs) who are either affected by the work or have knowledge to contribute to provide a complete, well rounded assessment. SME participation may include gas engineering/piping design, gas control, pressure regulation and control, gas construction, regulatory and permitting, procedures and risk assessment specialists.

5. **Accountable** – EDR begins with the design engineer(s) and associated multidisciplinary SME reviews. In practical terms, EDR is a continuous process; it continues throughout the construction and final inspection process to ensure accountability for "as-built" status and that commissioning / decommissioning is in accordance with design requirements. Sign off by the delegated position(s) of authority attests to completion of the steps identified in the procedures. Continuous management review; checks for indicators and metrics as identified in the Management Review discussion below. Reviewing accountability on a continuous basis will reduce risk in the EDR process.

6. **Layered & Transparent** – the EDR process must be transparent, establishing review requirements for standard, non-standard designs and management of change in well-defined policies and procedures. The process by definition must include a "layered" approach where predefined approval checkpoints, or approval "review gates," are used to ensure operability and constructability throughout the process.

7. **Proportionate –** the review process must be fit-for-purpose and scalable depending on the project. At a minimum, the review process should consider items identified in the checklists included in Appendix 6.

8. **Timely** – pre-defined design review gates and feedback loops should be considered for complex, non-standard designs to ensure efficient response to any required changes.

9. **Advisory –** the EDR process should be advisory and inform the designer/design team; the reviewer does not unilaterally make design change decisions but rather advises the design team and provides impartial advice.

10. **Understandability/Accessibility –** findings and advice are clearly expressed in terms that the design engineer or design team can clearly understand.

3.3 Typical Roles & Responsibilities

While an operator may have different titles for the roles described below, to be effective the EDR process must include a layered approach reviewed by appropriately trained and experienced individuals with subject matter experience. The layered approach that leads to final approval is typically preceded by interim design review gates. SME's collaborate and review the design at designated points in the design process to ensure technical conformance, constructability, and operability. The design review gate approval approach to gas EDR provides layers of protection to identify design anomalies that may impact pipeline safety, operational reliability and efficiency of operations. The concept is consistent with the Plan-Do-Check-Act (PDCA) philosophy incorporated in API RP 1173.

The EDR process starts with the design engineer and ends with final approval by a specified position of authority as defined by the operator. The process includes execution of the roles defined below and the defense-in-depth of multiple disciplines interacting to provide many perspectives. The process is robust through the necessary inclusion of stakeholders who could be affected by the work and have knowledge and competence to contribute to the assessment process. Below are examples of descriptions/positions of authority and the roles they may play in an operator's EDR process:

- **Engineering Executive** – the Executive sets the tone for the larger organization, procures necessary resources, and manages people, projects, programs and budgets in the engineering organization. The Executive may or may not be directly involved in the approval process for designs. The Executive should require comprehensive EDR with approval processes is being followed by competent people. The Executive must ensure a comprehensive engineer training program is established and continuously updated. The Executive should emphasize and encourage a questioning attitude, collaboration, robust management of change and documentation. The Engineering Executive typically has 6-8 years of progressive responsibility and leadership in gas operations management, engineering or construction;

- **Chief Engineer/Engineering Director** – this position has authority for all final engineering reviews and sign offs for all design types (standard, complex non-standard, etc.) and in some cases, directly reviews more complex high-risk designs. The scope of this role may include; final review of policies associated with design, approvals, management of change, process safety and pre-startup review policies. This position is typically held by an engineering Director or Executive within the organization and is a Licensed PE with appropriate gas engineering design, construction and operational experience (typically a minimum 5 years practical experience) or in lieu of a PE, an engineer in an appropriate discipline with more extensive construction and operational experience (typically greater than 8 years practical experience);

- **Technical Expert/Professional Engineer (PE) with Gas System Design Experience** – this position has delegated authority by the Chief Engineer/Engineering Director (if the role exists within an organization) for approval of all standard designs. Approves all non-standard designs prior to approval of the Chief Engineer/Engineering Director and reviews and approves all gas work methods and procedures, including design and construction standard drawings, policies and procedures. The Technical Expert typically has a PE with a minimum of 3-5 years of day-to-day gas engineering and operational experience; or, in lieu of a PE, equivalent competency including extensive design, construction and operational experience.

Typically, this means greater than 6 years of practical experience with successful completion of related subject matter continuing education coupled with 2 years of design approval focus;

- **Engineering Manager/Supervisor** – this position is responsible for a group of engineers involved in the design process. The Engineering Manager/Supervisor coordinates approvals from other departments and stakeholder groups within the organization prior to submission to the Engineering Director and/or Technical Expert. The Engineering Manager/Supervisor is typically an engineer with 3-5 years of system design and operational experience. This position typically includes successful completion of a Gas Engineering Certificate Program and continuing education;

- **Design Engineer/Competent Person(s)** – a competent person for purposes of this document is defined as the designer, or anyone that serves a technical role in the design or the design review process. For an engineer involved with the design, this position typically requires a minimum of 1-3 years practical experience in gas engineering design and/or gas operations commensurate with the complexity of the project or design. The Designer shall demonstrate gas system design competency through documented education in an appropriate engineering discipline and/or through successful completion of a Gas Engineering Certificate Program.

4. Training, Education and Experience of Competent Person(s)

The experience of an EDR team requires each participating individual to be technically competent for the design being reviewed. For example, if the design review includes a new pressure regulator station that is not an approved standard design (complex non-standard design), and if a third party review is specified in an operator's specific policy, the Competent Person(s) reviewing this non-standard design must have design and operational experience with gas pressure regulator stations including knowledge of industry acceptable practices, conformance with applicable codes and standards, as well as organization specific procedures and standards.

An operator's specific EDR process policy should specify education and demonstrated experience requirements for individuals involved in the design and approval process. Education and demonstrated experience requirements shall be commensurate with the nature, scope and complexity of the design. The EDR process may allow for delegation of authority for subject matter areas beyond the scope of the approval authorities' subject matter area of expertise. A summary of recommended gas engineering design review process roles, education, experience and other qualifications is included in Appendix 4.

4.1 Professional Engineer or Equivalent Technical Expert

While most design reviews can be conducted by Technical Experts within an organization, an operator's EDR process should specify when use of a PE with appropriate gas engineering design/design review experience is required. The PE shall be required to practice within the authorized scope of his/her license authority rules and scope of practice. It is the PE's responsibility to be knowledgeable of any practice restrictions that are based on law or regulation, as well as those that relate specifically to the PE's area of professional competence.

The Technical Expert or PE with gas system design experience should have appropriate gas system engineering and operations experience, be knowledgeable and have demonstrated competence appropriate for the design review being performed.

For purposes of gas system design reviews, a PE equivalent Technical Expert is defined as an experienced design or design review engineer with 8-10 years of gas engineering/operations experience. The Technical Expert should possess an engineering degree in an appropriate engineering discipline or successfully completed a Gas Engineering Certificate Program with 6-8 years of associated experience.

NOTE: The GTI Competent Engineer Education and Assessment Program is one example of an assessment-based learning offering that covers all identified American Gas Association recommended competencies for natural gas utility engineers[4] as well as the competencies identified in the NGA Gas Engineering Design Review Guideline. New engineers can take GTI's Registered Gas Distribution Professional and/or GTI's Certified Gas Transmission Professional Certificate coursework and take the assessment to verify competence. Experienced engineers may take the assessment as a gap analysis to determine areas for improvement.

4.2 Gas Distribution Engineering

Training/coursework/experience to demonstrate competency in the gas distribution engineering discipline is typically operator defined. The following knowledge domains appropriate for and commensurate with a specific design scope of work and responsibility should be considered:

- Overview of the Natural Gas Industry (exploration and production, gathering, transmission, distribution, utilization of natural gas);
- Properties of natural gas;
- Federal and state pipeline safety regulations, consensus codes and standards;
- Organization operating policies and procedures (including PSSR's, PSMS, SOP process);
- Material properties and design considerations (plastic, steel, cast iron, wrought iron);
- MAOP design considerations;
- Distribution pipeline design (buried piping systems, mains and services);
- Distribution pipeline repair methods and considerations;
- Pipeline crossing design (highways, bridges, culverts, railroads, waterways);
- Pipeline construction/abandonment practices (open trench, trenchless installation methods);
- Welding of steel pipe;
- Destructive and non-destructive testing of weld joints;
- Joining of plastic pipe;
- Destructive and non-destructive testing of plastic joints;
- Mechanical joining;
- Pipeline tapping, by-passing and installation of stopples;
- Pressure testing;
- Purging;
- Uprating;
- Odorization;

[4] AGA White Paper April 8, 2019, Skills and Experience for Effectively Designing Natural Gas Systems.

- Fundamentals of corrosion and cathodic protection;
- Pipeline coating systems;
- Gas measurement principles;
- Meter types, applications, sizing and selection for distribution applications;
- Pressure regulation and over-pressure protection fundamentals;
- Regulator types, sizing and selection for distribution applications;
- Regulator control instability causes and cures;
- Over-pressure protection methods, sizing and selection for distribution applications;
- Design of residential and commercial measurement and pressure control runs;
- Design of large commercial and industrial measurement and pressure control runs;
- Design of district regulator stations;
- Gas conditioning requirements and equipment selection for distribution applications;
- Noise considerations for pressure regulating stations;
- System loads and methods for determining design loads;
- Fundamentals of gas control, SCADA and telemetry;
- Gas flow calculations, pipe sizing, hydraulic modelling and network analysis;
- Permitting, environmental protection, easements, surveying;
- Overview of GIS systems, maps, record keeping systems;
- OSHA and other government design, construction and safety standards; and
- The potential for job function Abnormal Operating Conditions (AOC's).

Suggested Formal Education Courses:

Competency may be demonstrated by formal documented on-the-job (OTJ) experience and/or a combination of formal OTJ experience, course work and continuing education courses. The course knowledge domains provided by an operator sponsored training program utilizing an industry recognized curriculum is one option; or a training/certificate program provided by a recognized industry organization, equipment or material manufacturer, using an operator approved curriculum.

A comprehensive course curriculum and certificate of completion supported by examination are highly recommended to substantiate successful completion of coursework. In addition, college equivalency or continuing education hours need to be provided if applicable.

As one example, the Gas Technology Institute (GTI) offers the following programs:

- Fundamentals of Gas Distribution (online course);
- Gas Distribution Engineering 1;
- Gas Distribution Engineering 2;
- Pipeline Safety Regulatory Compliance;
- Measurement & Regulator Station Design;
- Gas Distribution Operations;
- Registered Gas Distribution Professional;
- GTI Competent Engineer Exam.

4.3 Gas Transmission Engineering

In addition to the Gas Distribution Engineering knowledge domains discussed in Section 4.2, supplemental transmission system specific training/coursework/experience to demonstrate competency in a Transmission Engineering discipline must consider the following knowledge domains (as required by assets considered in a specific design):

- Transmission pipeline design, abandonment and pipeline repair methods and considerations;
- ILI technologies / smart pig design considerations for the pipeline system;
- Design of pig launching and receiving facilities;
- Design of automatic shutdown and remote-control valve systems (ACV & RCV);
- Pressure testing of transmission pipelines;
- Uprating of transmission pipelines;
- Purging of transmission pipelines;
- Meter types, applications, sizing and selection for transmission applications;
- Energy measurement and gas quality monitoring instrumentation;
- Regulator types, sizing and selection for transmission applications;
- Regulator control instability causes and cures;
- Over-pressure protection methods, sizing and selection for transmission applications;
- Design of industrial measurement and pressure control runs;
- Design of gate stations;
- Design of gas heating systems;
- Design of compressor stations;
- Odorization requirements, systems and design considerations;
- Gas conditioning requirements and design considerations for transmission applications;
- Noise considerations for pressure regulating stations and compressor stations.

Suggested Formal Education Courses:

Competency may be demonstrated by formal documented on-the-job (OTJ) experience and/or a combination of formal OTJ experience, course work and continuing education courses. The course work knowledge domains may be provided by an operator sponsored training program utilizing an industry recognized, operator approved curriculum; or a training/certificate program provided by a recognized industry organization, equipment or material manufacturer, using an operator approved curriculum.

A comprehensive course curriculum and certificate of completion supported by examination are highly recommended to substantiate successful completion of coursework. In addition, college equivalency or continuing education hours need to be provided if applicable.

As one example, the Gas Technology Institute (GTI) offers the following supplemental programs for Transmission Engineers:

- Gas Transmission Operations;
- Transmission Pipeline Design & Construction;
- Compressor Station Design;
- Certified Gas Transmission Professional Certification Program;
- GTI Competent Engineer Exam.

4.4 Gas Processing Engineering

In addition to the above coursework, supplemental training/coursework/experience to demonstrate competency in the Gas Processing Engineering discipline should include the following knowledge domains as appropriate for the design under review:

- Design, Construction and Operation of compressed gas fueling stations;
- Natural gas processing facilities including liquefaction cycles, tank storage systems and vaporization systems;
- Portable LNG vaporization facilities;
- Gas conditioning systems (beyond the scope of filters, strainers and heaters included; in Gas Transmission and Distribution Competencies);
- Portable pipeline compressed natural gas injection/supply systems.

Suggested Formal Education Courses:

Competency may be demonstrated by formal documented on-the-job (OTJ) experience and/or a combination of formal OTJ experience, course work and continuing education courses. The course knowledge domains provided by internal operator sponsored training programs utilizing an industry recognized, operator approved curriculum are one option; or a training/certificate program provided by a recognized industry organization, equipment or material manufacturer, using an operator approved curriculum. Examples of some industry organizations and relevant courses are provided below.

A comprehensive course curriculum and certificate of completion supported by examination are highly recommended to substantiate successful completion of coursework. In addition, college equivalency or continuing education hours need to be provided if applicable.

As one example, the Gas Technology Institute (GTI) offers the following programs:

- Compressor Station Design;
- LNG Plant Design and Operations;
- GTI Competent Engineer Exam.

Additionally, the Gas Processors Association (GPA) Midstream Association offers the following programs:

- GPA offers a comprehensive course and certification in the use of the GPSA Engineering Data Book; an industry recognized technical reference related to determining natural gas operating and design parameters for gas processing facilities.

5. Standard Engineering Design

Distribution pipeline operators are subject to multiple layers of safety regulations establishing an operator's requirement for materials of construction, design of facilities, construction and maintenance practices and a variety of requirements to ensure system integrity. These requirements provide a framework of checks and balances to ensure that facility construction, operation and maintenance are performed consistently and, more importantly, provide pipeline operators with the fundamental rules to ensure sustainable positive safety outcomes. To ensure compliance and conformance with the intent of this regulatory framework, operators are required to maintain written construction, maintenance and operations procedures.

These documents, including manuals and standards that are filed with various regulatory agencies and unfiled documents that provide organizations with consistent guidance in aspects of day-to-day operations and construction, are specific to an operator's scope of operations and its assets being managed. As a result, operators have developed a series of standard designs and construction requirements specific to their assets and systems which are reviewed and approved for use internally and by designated, properly trained and competent contractors. The approval process is somewhat unique to each operator but typically incorporates a layered, integrated EDR process utilizing trained and experienced SMEs familiar with an operator's specific assets and the operating environments in which these assets are installed. Site/project specific designs typically incorporate a series or combination of approved standard designs, procedures, materials of construction and construction practices. Below are essential elements of standard engineering designs and procedure review considerations that each pipeline operator should incorporate into a standard design process.

5.1 Defining Standard Engineering Design Activities

Each pipeline operator should define standard design and construction activities. The review and approval process however are not limited to engineering design, but includes construction requirements/practices, materials of construction, testing, commissioning and de-commissioning requirements including pre-startup inspections, and obtaining clearances (permission to work) during the commissioning/de-commissioning process.

Below are typical standard pipeline system design activities to consider:

- Distribution and transmission piping system design, construction and abandonment including associated appurtenances;
- Design, construction, installation and abandonment of service lines, valves and associated appurtenances;
- Design, construction and installation of customer metering systems;
- Design, construction and installation requirements of over-pressure protection systems;

- Design, construction and installation practices of system isolation valves;
- Design, construction and installation of district pressure regulating stations;
- Design, construction and installation of piping system bridge, road and railroad crossings;
- Changes to prior approved standard designs, materials of construction, field changes (as-built) and installation practices;
- System Operating Procedure (SOP) review support associated with non-emergency planned construction or maintenance requiring the shutdown or interruption of the gas distribution or transmission system and associated clearances (permission to work); gas main tie-ins and main extensions as well as service connections requiring control of gas pressure.

5.2 Review and Approval of Standard Engineering Design/Construction Practices

Pipeline operators should develop a Standard Design/Construction Practices design review process that is:

- Appropriate for the level of complexity of the standard design/construction practice.
- Multi-layered, providing a multi-disciplined approach that is commensurate with scope and scale of the subject matter under design review;
- Conducted by competent individuals with direct knowledge of the technical subject matter under review;
- Includes final approval and sign off by a position of authority, typically an Engineering Manager/Supervisor and/or Engineering Director/Technical Expert;
- Ensures that personnel responsible for design and/or design implementation shall be appropriately trained in the design review process;
- Includes a process for assessing design/operational risk assessment, where appropriate, including identification of potential abnormal operating conditions (AOC's) resulting from design implementation;
- Includes consideration and development support, based on design/operational risk, of a Pre-Startup Safety Review process, System Operating Procedure process where required;
- Includes a continuous improvement review process for previously approved designs including a prescribed frequency of review (typically code mandated).

6. Complex and Non-Standard Engineering Design

Non-standard design, construction practices and procedure reviews are defined as proposed work that falls outside of the scope of *approved standard designs*, and/or where it is prudent based on a risk assessment or an organization's policy, that an independent review by a competent person(s) is warranted. This independent third-party review is typically conducted by a Technical Expert or PE with gas system design experience. The review and approval process include engineering design, construction requirements/practices, materials of construction, testing, application of commissioning and de-commissioning requirements such as pre- startup inspections and obtaining clearances (permission to work) during the commissioning/de- commissioning process.

6.1 Defining Complex and Non-Standard Design Activities

Below are examples of where a Complex, Non-Standard EDR should be considered:

- Design, construction and commissioning of a new, or reconfiguration of a District Pressure Regulating Station or Custody Transfer Station where reconfiguration is defined as any significant design change that may change original design operational variables such as capacity, pressure relieving systems, control lines and control systems, operational monitoring characteristics or equipment substitutions (other than like for like equipment replacement);
- Pipeline construction, abandonment and maintenance activity in the vicinity (as defined in company procedures or policies) of pressure regulation stations with focus on review and confirmation requirements of station monitoring and control points, sensing line locations and/or activity that may result in a system over pressurization and/or under pressurization AOC's;
- Uprating of distribution and transmission pipelines that are beyond the scope of standard uprate operating procedures with attention to end-use customer requirements, MAOP review of the pipeline, leak survey requirements, critical valve and isolation valve locations, overpressure protection and district regulator stations within the scope of the uprate;
- Complex design,construction and abandonment associated with distribution and transmission pipelines. Complex construction includes a design that is not included in an approved standard design that may involve multiple/complex tie-in's, systems requiring installation of a by-pass to maintain system pressure, and designs that impact system design pressures or other designs as determined by a risk assessment that a third-party review is recommended;
- Complex design and construction or significant modifications (as determined by a risk assessment) of compressor stations, LNG facilities, CNG vehicle fueling facilities, portable pipeline facilities and custody transfer (City Gate) stations.

6.2 Review and Approval of Complex, Non-Standard Designs and Construction Practices

Pipeline operators should consider development of a non-standard design/construction and operating practices EDR process that is:

- Fit-for-purpose, depending on the complexity of the non-standard design/construction practice and risk assessment if required;
- Multi-layered, providing a multidisciplined approach that is commensurate with the scope of the subject matter under design review;
- Conducted by competent, experienced individuals, typically a PE with gas engineering design experience or equivalent Technical Expert, with direct knowledge of the technical subject matter under review;
- Optional third-party reviews performed by external firms require final approval and formal sign off by a technical executive in the pipeline organization;
- Personnel responsible for design and/or design implementation shall be appropriately trained in the design review process;

- Includes a process for assessing design/operational risk assessment, where appropriate, including identification of potential AOC's resulting from design implementation;
- Includes, based on design/operational risk, a Pre-Startup Safety Review process and System Operating Procedure process where appropriate;
- Includes a process for construction pre-execution review with appropriate construction personnel including contractors.

7. Management of Change Policy/Operational Controls

The pipeline operator must establish a design approval management of change (MOC) policy that describes operational and administrative requirements and responsibilities. The MOC policy includes an approval process for field changes to previously approved standard/non-standard designs and/or associated system operating procedures. The MOC process should consider re-evaluation of previously approved designs that were not executed within the prescribed time frame (delayed projects) regardless of the reason for delay.

The pipeline operator should identify the potential risks associated with the change, execution delays and any required additional reviews and approvals prior to implementing the change. These changes include but are not limited to technical design, equipment specifications, system operation procedural modifications, project organizational changes (including any changes with assigned resources/contractors) and scope changes. The policy should consider permanent or temporary changes in addition to planning for the effects of the change for each situation.

The approval process for proposed changes to both standard and non-standard designs is based on the relative significance of the proposed change as determined by the original design engineer or designated alternate.

Design changes can be categorized into two Tiers:

Tier I – a field change that does not materially alter the fundamental design and will not alter ultimate operation of the pipeline, as determined by collaboration of the design/construction team SME's, relative to the original approved design. Tier I change(s) requires Design Engineer approval and, in some cases, as prescribed in an operator's policy, Design Engineer Supervisor/Manager approval;

Tier II – a design change that significantly alters the approved design and may result in operational changes of the pipeline (flows, pressures, temperatures, reliability, etc.) as determined by a risk assessment. Tier II change(s) requires a review equivalent to the original EDR - including, approval by the Engineering Director/Technical Expert, and, in some cases, the Engineering Executive.

NOTE: A delay in design construction execution, as defined in an operator's EDR policy, of a previously approved site-specific design should be considered a Tier II design change. This requires careful consideration as site operating variables, piping configurations and original design assumptions may have changed since it was originally reviewed**.** A post-change pre-execution review meeting should be considered including construction contractors as appropriate.

The pipeline operator's gas system EDR MOC policy should consider the following:

- Reason for change;
- Authority for approving changes;
- Analysis of implications;
- Assessment of potential work permit changes resulting from the design change;
- Documentation of change process;
- Communication of change to effected members of the project/construction team including additional pre-execution review meetings with associated contractor(s);
- Time limitations / scheduling;
- Reassessment of resources;
- Any resulting changes to construction staff qualifications and training (including contractors);
- Delays in execution of a site-specific design that may trigger re-examination of the original design and/or associated system operating procedure; and
- Any additional work or operating system changes beyond the scope of the originally proposed design or project work scope, in the same geographic area, which may have implications on the proposed change (overlapping work scope) or where the proposed change has implications on other projects/work.

8. Safety Assurance

Leadership should formalize EDR conformance assessments and develop associated metrics to monitor risk reduction results associated with the EDR process. These conformance assessments should consider:

- Identification of personnel to observe the conformance of parties engaged in the review and assess whether an adequate number of layers of protection are in place, appropriate to the design project's complexity;
- Assess how well documents are understood and if they are adequately accessible to support the EDR process;
- Observe the extent of transparency and accountability throughout the design, construction, and inspection process.

Organizations should consider developing and executing a plan for auditing the effectiveness of the Engineering Design Review process and review results in a Management Review. Metrics can be drawn from the list described below in item 9. The plan should determine if corrective actions are appropriately taken and establish a schedule for implementation, consistent with API RP 1173. The plan should also stimulate the involvement of employees regardless of position to make recommendations and contribute to decisions. One should consider as part of the audit process the extent of incident investigation and lessons learned, procedures for identifying incidents to investigate, adequacy of procedures to determine cause and how well corrective actions are assigned, monitored and tracked. The plan should have provisions to determine if there is any potential for abuse of the Delegation of Authority to subject matter experts not adequately prepared.

9. Continuous Improvement Practices Related to Engineering Design/Management Review

The pipeline operator's gas system EDR policy should include a continuous improvement process. Appropriate data should be reviewed and evaluated to ensure the pipeline or facility design is operating as intended. Each standard design, construction procedure and associated procedures for commissioning and de-commissioning of facilities should be periodically reviewed, at a minimum, in accordance with any code specific requirements. Periodic reviews should include metrics on the following, which will be monitored during the management review process:

- Stakeholder feedback, including feedback from field personnel involved in both construction and operations (including contractors);
- Equipment reliability, performance and availability;
- Gas system operational performance;
- Equipment manufacturer notifications;
- Incident investigations, near-miss evaluations and lessons learned;
- Changes in policies and codes; and
- Results of risk management reviews, internal and external audits.

The output of the continuous improvement periodic reviews of gas system designs should include a summary of changes to specific designs, feedback integration into the MOC process, and communication of change resulting from these reviews, including feedback to training organizations.

10. Documentation and Recordkeeping

The pipeline operator's gas system EDR policy should include requirements for identification, distribution and control of documents to memorialize the review process. The policy should specify responsibilities for document approval/sign-off and re-approval, and identify controls needed to assure that appropriate documents required to support the EDR process, construction and commissioning/de-commissioning process are readily available and accessible to workers performing an activity, and that they remain legible and readily identifiable. One should evaluate how consistently documents are accessed and determine if there are areas of the organization where access is a concern.

These documents typically include:

- Design drawings and sketches;
- Calculations;
- Materials of construction;
- Field construction data such as pipe joining records, system testing records including pressure testing records, etc.; and
- Work package data, including commissioning/de-commissioning PSSR's and SOP's.

11. Summary and Conclusions

EDR, as applied to gas system construction and operations, is an essential process that is fundamental in controlling construction and operational risk. EDR is a process executed by competent individuals and/or teams of individuals that have demonstrated subject matter experience coupled with, in some cases, practical operational and construction experience. The process is scalable, with the level of review and approval commensurate with the complexity of the design. The defense-in-depth strategy to minimizing and reducing operational risk associated with gas system engineering designs is underpinned by a layered approach of review. In summary, a comprehensive, consistently executed organizational policy that incorporates a layered approach of review utilizing competent individuals, commensurate with the complexity of the design, will result in maximizing public safety value.

APPENDIX

1. Sample Review Process for Standards, Procedures & Construction Practices

2. Sample Review Process for Application of Standard Designs to Site Specific Projects

3. Sample Review Process for Site/Project Specific Complex, Non-Standard Designs

4. Gas System Engineering Design Review Roles, Responsibilities and Qualification Considerations

5. References

6. Sample Complex Design & Construction Review Checklists

   A. Intrastate Transmission Pipelines
   B. Distribution Pipelines
   C. District Pressure Regulator Stations
   D. Gate Stations
   E. Bridge & Railroad Crossings
   F. Uprating Intrastate Transmission and Distribution Pipelines

7. Sample System Operations Procedure (SOP)

8. Sample Pre-Startup Safety Review Checklist

9. Sample Change Control Procedure for Construction Projects

10. EDR Guideline Safety Management System Conformance Independent Assessment

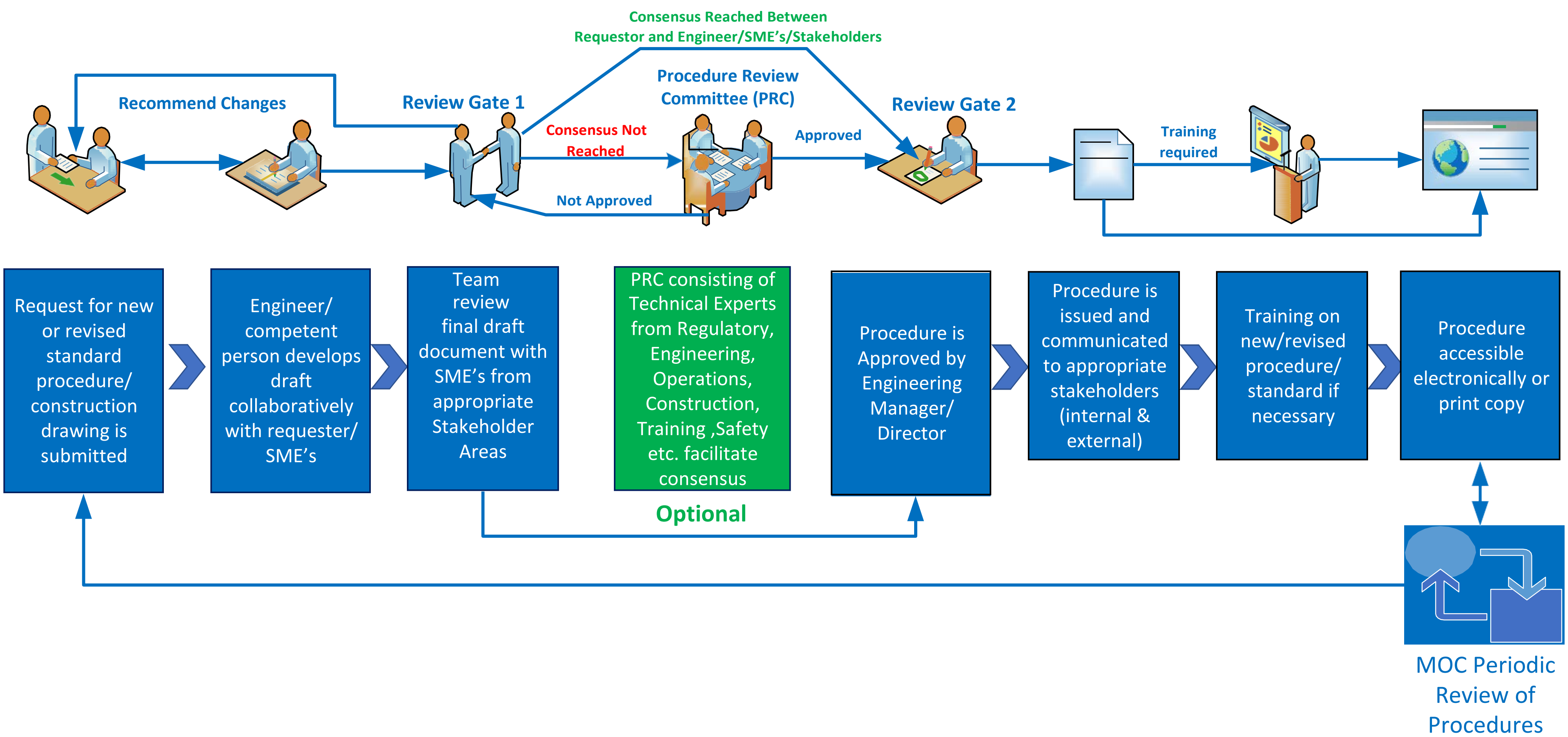
Note:

The SAMPLE Checklists and Procedures are intended to provide operators with examples and a framework for consideration in development of company specific checklists and procedures. It is further recognized that the complexity of each design and company specific operating assets may vary and as a result, each operator should carefully examine the applicability of the Appendix documents contained within this Guideline.

Appendix 1

Sample Review Process for Standards, Procedures & Construction Practices

Appendix 1 Sample Review Process for Standards, Procedures & Construction Practices

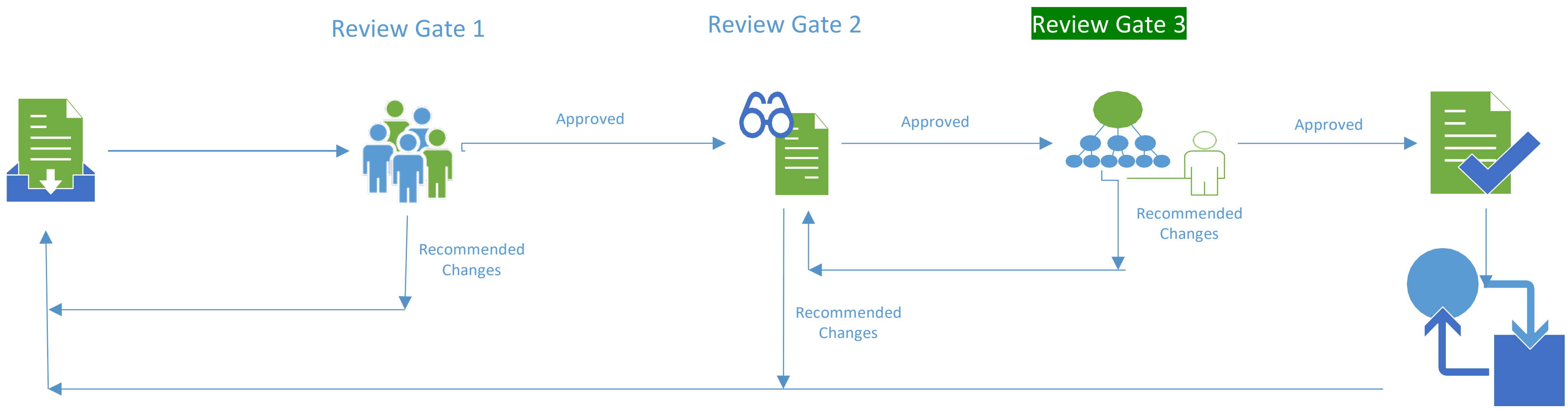


Note: ***This process may vary structurally and by organization however should be included in each company specific Design Review Policy or Procedure.*** The procedure/construction drawing development & MOC process typically includes *1-2 Review Gates* prior to final approval depending on the complexity of the procedure, stakeholder impacts and the ability to reach consensus among stakeholders. In some larger organizations, a "Procedure Review Committee", or PRC, is used to build consensus around a proposed process change the SME's cannot reach agreement on. Final approval is typically by the Engineering Standards & Procedures Manager/Director. More complex procedures, designs, drawings may include development by and/or independent external review by a competent third party.

Appendix 2

Sample Review Process for Application of Standard Designs to Site Specific Projects

Appendix 2 Sample Review Process for Application of Standard Designs to Site Specific Projects



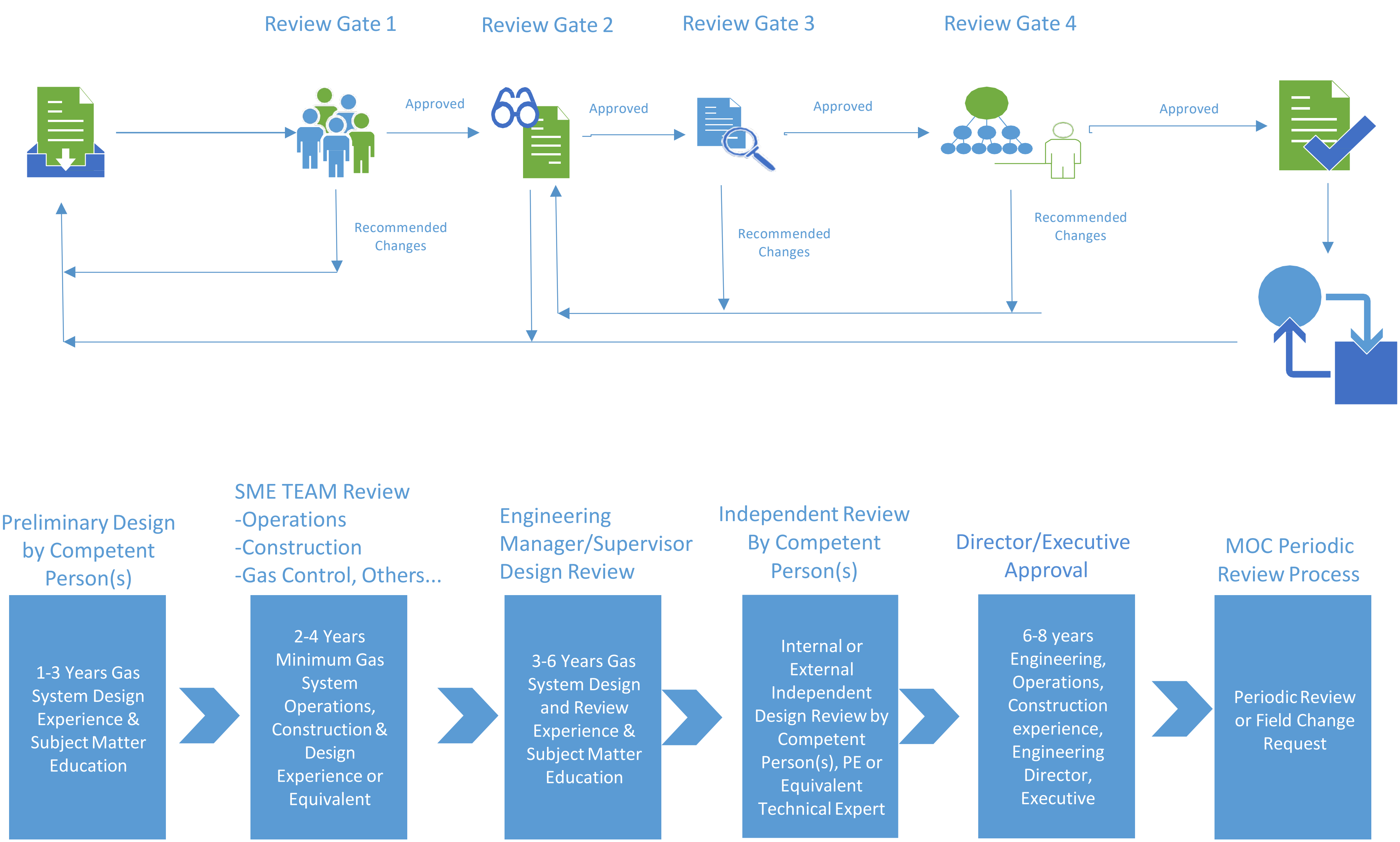
Preliminary Design by Competent Person(s)	SME TEAM Review -Operations -Construction -Gas Control, Others...	Engineering Manager/Supervisor Design Review	Director/Technical Expert Approval (Optional)	MOC Periodic Review Process
1-3 Years Gas System Design Experience & Subject Matter Education	2-4 Years Minimum Gas System Operations, Construction & Design Experience or Equivalent	3-6 Years Gas System Design and Review Experience & Subject Matter Education	6-8 years Engineering, Operations, Construction experience, Engineering Director, Executive	Periodic Review or Field Change Request

Note: Depending on the complexity of the standard design, the size and scale of company specific operations, the review process may incorporate *2-3 levels of review*. In many cases, the Preliminary Design by a Competent Person incorporates a “design team” combining the SME Team review with work by the Designer, then reviewed and approved by the Engineering Manager/Supervisor (***essentially a two-step process***). For more complex standard designs, or larger, organizations managing more complex systems, the process may be expanded as shown above to include optional review by the Engineering Director/Technical Expert or for routine designs on a “spot check” periodic basis. Regardless of size/scale of an organization or standard design complexity, the Process MUST include design review gates, review by competent person(s) with final approval by a position of authority. ***The key to maximizing public safety value and system reliability associated with gas engineering designs is in the “layers of protection” a properly executed design review process results in rather than relying on a single level review by an individual.***

Appendix 3

Sample Review Process for Site/Project Specific Complex, Non-Standard Designs

Appendix 3 Sample Review Process for Site/Project Specific Non-Standard Designs



Note: Like the Standard Design Review Process, the Non-Standard review process *is scalable based on project complexity*, the size of a company and complexity of assets being managed. A fundamental element in Non-Standard Design Review is the independent review by Competent Person(s). In this case, Competent Person(s) is defined as an ***internal employee OR contractor*** with a PE **AND** associated gas experience in the subject matter under review (minimum 3- 5 years' experience) OR ***equivalent*** Technical Expert which includes an experienced gas engineering professional with an engineering degree in an appropriate discipline with 6-8 years' experience and successful completion of a Gas Distribution/Transmission Engineering Certificate Program and associated continuing education. Review Gate 3 & 4 should be considered based on the complexity of design / design change as described in a company specific EDR process.

Appendix 4

Gas System Engineering Design Review Roles, Responsibilities and Qualification Considerations

Gas System Engineering Design Review Role & Responsibility Summary / Associated Qualifications

NOTE: These are *examples* of typical process roles however these roles may not be present in every company. The company specific gas engineering design review policy shall define roles and responsibilities.

Process Responsibility: Engineering Executive

Description: overall engineering design end-to-end process responsibility including personnel responsible for gas system designs from concept through final approval. Additional responsibilities include overall team leadership and process conformance, compliance with all local, state and federal design requirements, design conformance with applicable company standards, work methods, procedures and policies.

Required Education: B.S. in an appropriate Management/Business Administration or Engineering Discipline, advanced degree, P.E. or equivalent preferred however not required.

Gas System Experience: 6-8 years of progressive responsibility and leadership in gas operations management, engineering or construction.

Additional Recommended Education / Certification: Advanced professional training and continuing education related to pipeline operations regulatory requirements, gas engineering design, construction and operations and Pipeline Safety Management Systems (PSMS) leadership, overall multi-disciplinary gas business background.

Process Responsibility: Chief Engineer/Engineering Director

Description: this position has authority for all final engineering reviews and sign off for all design types (standard, complex non-standard, etc.) and in some cases, directly reviews more complex high-risk designs. The scope of this role typically includes final review of policies associated with design, approvals, management of change, process safety and pre-startup review policies.

Required Education: B.S. in an appropriate Engineering Discipline, advanced degree, P.E. or equivalent is preferred however not required.

Gas System Experience: minimum 6-8 years (typically greater than 8 years) of progressive responsibility and leadership in gas operations, engineering or construction.

Process Responsibility: Chief Engineer/Engineering Director (Cont'd)

Additional Recommended Education / Certification: Advanced professional training and continuing education related to gas engineering design, construction and operations and Pipeline Safety Management Systems (PSMS) leadership and other professional gas system coursework.

Process Responsibility: Technical Expert / Professional Engineer (PE) with Gas System Design Experience

Description: responsible for impartial review independent of the Design Engineer or Engineering Project Development Team (Design Engineer(s), SME Review and Engineering Manager Review). Review typically reserved for complex, site/project specific non-standard engineering designs typically performed by a Licensed Professional Engineer (PE) with demonstrated subject matter experience, or documented extensive gas system design, operations and/or construction experience OR Equivalent Technical Expert.

Required Education: B.S. in an appropriate Engineering Discipline, advanced degree preferred, P.E. or equivalent Technical Expert (which includes successful completion of the Registered Gas Distribution Professional Program and/or the Certified Gas Transmission Professional (CGTP) Program) or comparable gas system design review certification from a company approved continuing education provider.

Gas System Experience: With a P.E., minimum 3-5 years practical gas system design, operations and/or construction experience. P.E. equivalent competency (in lieu of a PE) includes extensive design, construction and operational experience. Typically, this means greater than 6 years of practical experience with successful completion of related subject matter continuing education coupled with 2 years of *design approval focus.*

Additional Recommended Education / Certification: For P.E. equivalent status, successful completion of the GTI Registered Gas Distribution Professional Program AND/OR Certified Gas Transmission Professional Program (CGTP) or comparable gas system design certification program from a company recognized continuing education provider. Advanced professional training and continuing education related to subject matter under review including gas processing facility design, construction and operational reviews.

Process Responsibility: Engineering Manager / Supervisor

Description: engineering team supervisory role, responsible for engineering design area(s) and for design engineer leadership and development. Responsibilities include ensuring engineering design process conformance with all designs in addition to technical oversight and approvals in accordance with all local, state and federal code requirements, company specific procedures and industry acceptable practices.

Process Responsibility: Engineering Manager / Supervisor (Cont’d)

Ensure design packages are complete including commissioning and decommissioning procedure references and/or development.

Required Education: B.S. in an appropriate Engineering Discipline, advanced degree preferred or equivalent Technical Expert (which includes successful completion of the Registered Gas Distribution Professional Program and/or the Certified Gas Transmission Professional (CGTP) Program) or comparable gas system design review certification from a company approved continuing education provider.

Gas System Experience: 3-5 years practical design approval experience.

Additional Recommended Education / Certification: Participation in GTI Registered Gas Distribution Professional Program or other professional gas system coursework working towards Certificate with Operations or Engineering focus.

Process Responsibility: Design Engineer / Competent Person(s)

Description: responsible for development of assigned engineering design, developing operating or maintenance procedures associated with pipelines/pipeline facilities (see 49 CFR 191.3) and/or member of the design review team (including SME’s) focused on design operability, constructability, pipeline safety and system reliability.

Required Education: B.S. in an appropriate Engineering Discipline preferred, OR practical gas operations, construction and/or gas control experience as specified below.

Gas System Experience: 1-3 years practical design experience with B.S., 4-8 years related operational/gas construction experience without an engineering degree.

Additional Recommended Education / Certification: Participation in GTI Registered Gas Distribution Professional Program or other professional gas system coursework working towards Certificate with Operations or Engineering focus. For non-degree SME’s, professional training and continuing education related to subject matter under review or other gas system coursework.

Appendix 5
References

1. Skills and Experience for Effectively Designing Natural Gas Systems, AGA White Paper, April 8, 2019.

2. Design Responsibility in Integrated Project Delivery: Looking Back and Moving Forward, David J. Hatem, PC, Donovan Hatem LLP Boston | New York January 2008.

3. Defining and Allocating "Design Responsibility" in Complex Projects, Skellenger Bender, 2007.

4. The Engineer of Record and Design Responsibility, Jack D. Gillum P.E., Journal of Performance of Constructed Facilities, May 2000.

5. Design Review Principles and Practice, Design Council UK, 2013.

6. Design Quality Review, National Grid Presentation, 2017.

7. Design Quality Assessment Using Process Review, Danny Kahler P.E, Delcon Corporation, Society for Quality Energy & Environmental/Design and Construction Conference, November 2007.

8. Design Quality Control Plan, US Army Corps of Engineers, Engineering Division, April 2010

9. USAC Engineering and Construction Quality Management Regulation, ER1110-1-12, July 2006.

10. Constructibility and Design Reviews; Analysis and Recommendations for Improvement, J.G. Kirby, R.P. Cannalte, D.K. Hicks and E.J. Japel, US Army Corps of Engineers Constructional Engineering Research Library Technical Report P-89/15, US Army Corps of Engineers 1989.

11. Pipeline Safety Management System Requirements, American Petroleum Institute API Recommended Practice 1173, First edition, July 2015 (Washington, DC: American Petroleum Institute, 2015).

Appendix 6

Sample Complex Design & Construction Review Checklists

A. Intrastate Transmission Pipelines
B. Distribution Pipelines
C. District Pressure Regulator Stations
D. Gate Stations
E. Bridge & Railroad Crossings
F. Uprating Intrastate Transmission & Distribution Pipelines

Appendix 6-A Sample Design Review Checklist - Transmission Pipeline	
Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	*Design of Transmission Lines and Pipelines with MAOPs of 125 PSIG or Greater*

TASK	REFERENCES	DATE or N/A
PROJECT FILE		
Verify Scope of work (project initiation form and scope document).		
-Confirm that scope document was routed appropriately.		
Verify Process Hazard Assessment (PHA) review form completed.		
-Confirm any action items are closed.		
Verify Project Complexity Score.		
DESIGN DRAWINGS		
Review design cover page for appropriate information.		
-Location, length, diameter, pressure, etc.		
Verify that construction/design notes are complete.		
-Weld X-Ray requirements CWI, GPS, etc.		
-Wall thickness, grade		
-Pressure test requirements.		
-MAOP, MOP, % SMYS, etc.		
-Verify Corrosion Review of design and comments incorporated in plans.		
-Review SMYS calcs, verify proper wall thickness and strength for all components.		
Review valve design/utilization.		
-Verify line valves located every mile.		
-Verify purge points between all main valves per Company Standards.		
-Verify proper valve support for valves 12-inch and larger.		
-Verify requirement and design for Remotely Operated Valves.		
Review tie-in details		
Verify design is piggable, 3R elbows, barred tees, etc.		
Verify that launcher / receiver design (perm or temp) in accordance with design standards.		
Verify that a odorant pickling procedure is incorporated into the design (>2500').		
Confirm that appropriate markers are included in design.		
Verify materials are specified with appropriate level of detail.		
-Identified as stock or non-stock and responsible supplier.		
-Confirm all materials on order or on schedule based on time of review.		
-Coatings are specified.		
Verify any special permitting requirements.		
-Confirm design in accordance with any special permit requirements.		
Review for special roadway crossings/ foreign utilities.		
Schedule design hold point 1 design/construction review meeting.		
Determine if NYS PSC Article VII filing and Environmental Review (NYS)		

Appendix 6-A Sample Design Review Checklist - Transmission Pipeline	
Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	*Design of Transmission Lines and Pipelines with MAOPs of 125 PSIG or Greater*

TASK	REFERENCES	DATE or N/A
WORK PACKAGE		
Confirm all appropriate forms are included in the work package.		
Pressure test form, with top part of form completed.		
Review Draft SOP.		
-Confirm time/temp restrictions are included.		
-Confirm pre-heat and post bake needs are included.		
Review estimate.		
Signed Delegation of Authority (DOA).		
-Confirm updated estimate reflected in DOA.		
NYS DPS 30 Day Notice of Proposed Construction including construction start date (NY only)		
POST Design Review		
Update Project List.		
Elevate any process / design concerns or roadblocks, etc. to HUB board.		
Send drawings for any applicable state permit / grant of location.		
Incorporate any changes from TVC Hold Point 1 Meeting.		
Develop construction bid specs.		
Reinforce TVC Requirements.		
-CMTR Calculations completed and sent to Transmission Engineering for approval.		
POST CONSTRUCTION		
Send copy of pressure test report to PSC certifying MAOP of pipeline (NY only)		
Update "Issued for Construction" drawings based on "As-Built" conditions		
Send copy of As-Built drawings to Mapping		
Send copy of As-Built drawings Damage Prevention		

Other Notes/Comments, Company Specific Procedure References:

Appendix 6B Sample Design Review Checklist - Distribution Pipeline		
Project Name:		
City/Town:		
WO#:		
Engineer:		
Design Review By:		
Design Std:	*Design of Distribution Mains*	

TASK	REFERENCES	DATE or N/A
PROJECT FILE		
Verify Scope of work (project initiation form and scope document).		
-Confirm that scope document was routed appropriately.		
Verify Project Complexity Score.		
DESIGN DRAWINGS		
Review design cover page for appropriate information.		
-Location, length, diameter, pressure, etc.		
Verify that construction/design notes are complete.		
-Weld X-Ray requirements		
-Wall thickness, grade		
-Pressure test requirements.		
-MAOP, MOP, % SMYS, etc.		
-Verify Corrosion Review of design and comments incorporated in plans.		
-Review SMYS calcs, Verify proper wall thickness and strength for all components.		
Verify that valves are located for appropriate isolation, sectionalizing, etc.		
-Verify proper valve support for valves 12-inch and larger.		
Review tie-in details		
Verify details are appropriate for abandonment of existing main.		
Verify that a odorant pickling procedure is incorporated into the design (>2500')		
Verify materials are specified with appropriate level of detail.		
-Identified as stock or non-stock and responsible supplier.		
-Confirm all materials on order or on schedule based on time of review.		
-Coatings are specified.		
Verify any special permitting requirements (e.g. R/R, DOT, etc).		
-Confirm design in accordance with any special permit requirements.		
Review for special roadway crossings/ foreign utilities.		
WORK PACKAGE		
Confirm all appropriate forms are included in the work package.		
Review Draft SOP.		
-Confirm time/temp restrictions are included.		
Review estimate.		
Signed Delegation of Authority (DOA).		
-Confirm updated estimate reflected in DOA.		
POST DESIGN REVIEW		
Update Project List.		
Elevate any process / design concerns or roadblocks, etc. to Executive		
Send drawings for any applicable state permit / grant of location.		
Other Notes/Comments, Company Specific Procedure References		

Appendix 6C Sample Design Review Checklist- District Pressure Regulator Station

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	*Design of Gas Regulator Stations*

TASK	REFERENCES	DATE or N/A
PROJECT FILE		
Verify Scope of work (project initiation form and scope document).		
-Confirm that scope document was routed appropriately.		
Verify station ownership, O&M agreements, custody transfer, etc.		
Verify Process Hazard Assessment (PHA) review form completed.		
-Confirm any action items are closed.		
Verify Project Complexity Score.		
DESIGN DRAWINGS		
Review design cover page for appropriate information.		
-Location, length, diameter, pressure, etc.		
Verify that construction/design notes are complete.		
-Weld X-Ray requirements		
-Wall thickness, grade		
-Pressure test requirements.		
-MAOP, MOP, % SMYS, etc. (MAOP confirmed with asset owner).		
-Verify Corrosion Review of design and comments incorporated in plans.		
-Review SMYS calcs, Verify proper wall thickness and strength for all components.		
-Confirm SMYS <20% for all components.		
-Confirm that the entire station from inlet to outlet valve is designed for inlet MAOP.		
Review regulator selection, sizing calculations, and overpressure protection.		
Review pipe sizing for velocity, vibration and noise potential.		
Review valve design/utilization.		
-Verify appropriate placement of inlet/outlet valves.		
-Verify appropriate use of gate/ball/valve.		
Confirm that controls lines are designed in a safe location and per standard. New control lines in the public ROW should be at least 1-1/4" SCH80.		
Verify appropriate civil details, for building, supports, etc.		
Verify inclusion of a grounding plan if applicable.		
Verify complete electrical/control designs. SCADA location, power, comms.		
Confirm vent poles are utilized for vaults as needed.		
Verify lightning protection at insulating flanges for above grade transitions.		
Verify motion detection, intrusion, gas detection, etc.		
Verify materials are specified with appropriate level of detail.		
-Identified as stock or non-stock and responsible supplier.		
-Confirm all materials on order or on schedule based on time of review.		
-Coatings are specified.		
Confirm appropriate level of detail for abandonment of existing station **and control lines**.		
Verify any special/building permitting requirements.		
-Confirm design in accordance with any special permit requirements.		

Appendix 6C Sample Design Review Checklist- District Pressure Regulator Station

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	Design of Gas Regulator Stations

TASK	REFERENCES	DATE or N/A
WORK PACKAGE		
Confirm all appropriate forms are included in the work package (work package, Environmental, maps, service info, records, etc.).		
Review Draft SOP.		
-Confirm time/temp restrictions are included.		
Review estimate.		
Signed Budget/Spend Approval Delegation of Authority (DOA).		
-Confirm updated estimate reflected in DOA.		
POST Design Review		
Update Project List.		N/A
Elevate any process / design concerns or roadblocks, etc. to Engineering		N/A
Develop construction bid specs		N/A

Other Notes/Comments: References include any Company Specific Procedures No's, Policies etc.

Appendix 6D Sample Design Review Checklist - Gate Station

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	*Design of Gas Regulator Stations*

TASK	REFERENCES	DATE or N/A
PROJECT FILE		
Verify Scope of work (project initiation form and scope document).		
-Confirm that scope document was routed appropriately.		
Verify station ownership, O&M agreements, custody transfer, etc.		
Verify Process Hazard Assessment (PHA) review form completed.		
-Confirm any action items are closed.		
Verify Complexity Score.		
DESIGN DRAWINGS		
Review design cover page for appropriate information.		
-Location, length, diameter, pressure, etc.		
Verify that construction/design notes are complete.		
-Weld X-Ray requirements CWI, GPS, etc.		
-Wall thickness, grade		
-Pressure test requirements.		
-MAOP, MOP, % SMYS, etc. (MAOP confirmed with asset owner).		
-Verify Corrosion Review of design and comments incorporated in plans.		
-Review SMYS calcs, Verify proper wall thickness and strength for all components.		
-Confirm SMYS <20% for all components.		
-Confirm that the entire station from inlet to outlet valve is designed for inlet MAOP.		
Review regulator selection, sizing calculations, and overpressure protection.		
Review pipe sizing for velocity.		
Review valve design/utilization.		
-Verify appropriate placement of inlet/outlet valves.		
-Verify appropriate use of gate/ball/valve.		
Confirm that controls lines are designed in a safe location and per standard.		
Verify appropriate civil details, for building, supports, etc.		
Verify inclusion of a grounding plan if applicable.		
Verify complete electrical and control designs.		
Verify lightning protection at insulating flanges at above grade transitions.		
Verify motion detection, intrusion, gas detection, etc.		
Verify odorant is acceptable: system, volume, odorizer, containment.		
Verify materials are specified with appropriate level of detail.		
-Identified as stock or non-stock and responsible supplier.		
-Confirm all materials on order or on schedule based on time of review.		
-Coatings are specified.		
Verify any special/building permitting requirements.		
-Confirm design in accordance with any special permit requirements.		
Schedule hold point 1 design/construction review meeting.		
Determine if PSC Article VII filing needed (NYS)		

Appendix 6D Sample Design Review Checklist - Gate Station

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	*Design of Gas Regulator Stations*

TASK	REFERENCES	DATE or N/A
WORK PACKAGE		
Confirm all appropriate forms are included in the work package.		
-Confirm as needed		
Pressure test form, with top part of form completed.		
Review Draft SOP.		
-Confirm time/temp restrictions are included.		
-Confirm pre-heat and post bake needs are included.		
Review estimate.		
Signed Delegation of Authority (DOA).		
-Confirm updated estimate reflected in DOA.		
PSC 30 Day Notice of Proposed Construction including construction start date (NY Only)		
POST Design Review		
Update Project List.		
Elevate any process / design concerns or roadblocks, etc. to Executive		
Incorporate any changes from Hold Point 1 Meeting		
Develop construction bid specs		
Reinforce TVC Requirements.		
CMTR Calculations completed and sent to Pressure Regulation Engineering for Approval.		
POST CONSTRUCTION		
Send copy of pressure test report to PSC certifying MAOP of pipeline (NY		
Update "Issued for Construction" drawings based on "As-Built" conditions		
Send copy of As-Built drawings to Mapping		
Send copy of As-Built drawings Damage Prevention		

Other Notes/Comments, Company Specific Procedures:

Appendix 6E Sample Design Review Checklist- Pipeline Bridge Crossings

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	Design Requirements for Installation of Gas Main on Bridges

TASK	REFERENCES	DATE or N/A
COMPLETE TRANSMISSION OR DISTRIBUTION CHECKLIST IN ADDITION TO THE FOLLOWING:		
Verify appropriate placement of pipe and constructability.		
-Not lowest hanging component or subject to damage, etc.		
-Equipment needed for access or installation. Barges, scaffolding, etc.		
-Is existing piping in the way of proposed?		
-Will removal of existing piping require other additional measures/equipment and effect of permitting?		
-Confirm appropriate permits and real estate access needed is identified.		
Confirm calculations are all performed in accordance with bridge requirements for pipe support and bridge attachment.		
-Verify max support spacing is adequate.		
-Verify the need for an expansion joint.		
Verify appropriate detail for pipe roller/hardware, attachment bracket, and coating of these materials. Include all anchors and any other materials or equipment that require special order and fabrication. Special drill bits, etc.		
Verify appropriate detail for bridge abutments and materials needed.		
Verify isolation valves on both sides of the bridge.		
Verify appropriate coating for bridge pipe.		
Weld X-Ray requirements, 100% on bridges.		
(MA Only) Review DPU bridge letter for appropriate detail and format.		
POST Design Review		
Submit bridge design to appropriate permit agency for bridge ownership.		
(MA Only) Send bridge letter to DPU for approval of the installation.		
Send critical valve information to Operations Engineering.		

Other Notes/Comments, Company Specific Procedures

Appendix 6E Sample Design Review Checklist - Railroad Crossings

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	*Design Requirements for Installation of Casings (5.3 Railroad Crossings); Casing installations*

TASK	REFERENCES	DATE or N/A
COMPLETE TRANSMISSION OR DISTRIBUTION CHECKLIST IN ADDITION TO THE FOLLOWING:		
Verify appropriate placement of crossing and constructability.		
-Adequate space for excavations, equipment, etc. for boring.		
-Appropriate location for casing vents.		
Confirm design and calculations are performed in accordance with AREMA or applicable railroad owner/agency.		
-Adequate depth of cover.		
-Verify test borings and/or pits completed (if necessary).		
Verify appropriate detail for casing and materials needed.		
Verify isolation valves on both sides of the railroad.		
Verify appropriate cathodic protection for carrier and casing.		
Confirm appropriate permits and real estate access needed is identified.		
POST Design Review		
Work with real estate to submit permit and establish insurance needs, etc.		
Send critical valve information to Operations Engineering.		

Other Notes/Comments, Company Specific Procedures

Appendix 6F Sample Design Review Checklist - Upratings

Project Name:	
City/Town:	
WO#:	
Engineer:	
Design Review By:	
Design Std:	Uprating Pipelines to 125 psig or Greater; Uprating Pipelines to Less than 125 PSIG

TASK	**REFERENCES**	**DATE or N/A**
TRANSMISSION OR DISTRIBUTION CHECKLIST MAY BE NECESSARY FOR DESIGN OF MAINS IN ADDITION TO THE FOLLOWING:		
Review Pre-Uprating Checklist		
-Verify review of all mains.		
-Verify review of all services and customer/address list.		
-Verify receipt of all pressure test records.		
-Verify review of corrosion history.		
'-Verify review of impacted regulator stations.		
-Verify review of leak history.		
-Verify operations regulatory compliance notification/review.		
-Verify pre-uprate meeting scheduled/complete.		
-Verify pre-uprate service inspection scheduled/complete.		
-Verify pre-uprate leak survey scheduled.		
-Verify DPU notification.		
Review Uprating Procedure		
-Verify source of pressure increase.		
-Verify system separation (connection and abandonment detail).		
-Verify system checkpoints.		
-Verify pressure chart location.		
-Review Draft SOP		
Review Post-Uprating Checklist		
Verify proper NGA operator qualification (Task 28 & 70).		
Verify complete uprate binder		
Verify design in accordance with company standard.		
Verify design in accordance with 49 CFR 192 Subpart K.		

Other Notes/Comments, Company Specific Procedures

Appendix 7

Sample System Operations Procedure (SOP)

Gas System Operations Procedure (SOP)

1. Purpose

The purpose of this Policy is to provide a uniform method of preparing, processing and implementing System Operating Procedures (SOP's), including notifications for performing shutdowns or tie-ins on gas transmission or distribution mains.

This Policy applies to non-emergency planned construction or maintenance requiring the shutdown or interruption of the gas transmission or distribution system; all gas main tie-ins and main extensions; as well as all service connections requiring a full tee tie-in. Non-emergency planned work is defined as work with sufficient time to allow an SOP to be written and reviewed in preparation of the work.

In addition an SOP should be utilized when work is proposed to be done that does not fall under the normal requirements for an SOP, but where the nature of work makes it prudent to pre-plan for the risk involved.

2. Responsibilities

<u>Gas Control</u> shall be responsible for:

- Review and approve all gas System Operating Procedures (SOP's).
- Approve all main valve operations on the gas system associated with the SOP's, other than curb cocks or meter sets.
- Assist in the review of SOP's with Instrumentation & Regulation (I&R), Project Engineering & Design, Gas Operations Engineering, Gas Field Operations and Construction and LNG/Propane Air as required.
- Notify I&R when construction is located within 200 feet of regulator stations, gate/take stations, gas plants, gas holders and/or compressor facilities. Electronic SOP's shall be sent to I&R for review when critical facilities are identified, prior to Gas Control review.
- Coordinate with I&R as required when taking regulators stations out of service.
- Ensure the most recent version of the SOP is at the field location – verify the SOP number and revision number.
- Updating in-progress SOP's with completed steps/details communicated from field representatives, including but not limited to pressure readings, valve operations, flow testing, pipe joining, etc.
- Place the appropriate status of the job in the SOP system as communicated by the field organization performing the work.
- Produce a report on a regular basis, as a recurring task on the calendar, showing open SOP's, obtain current status with the field and update the SOP status as necessary.

<u>Gas Instrumentation & Regulation (I&R)</u> shall be responsible for:

- Review and approve all SOP's which involve gate stations, regulator stations, system interconnect valves, gas plants, compressors, supplemental odorization assessment/injection or where the construction is located within 200 feet of these facilities.
- Generate final SOP's when I&R work requires an SOP
- Operate and tag regulator station valves and/or system valves as directed by Gas Control during the SOP including shutdowns and restoration

- Review final approved SOPs with I&R crews prior to the execution of the SOP
- Ensure the most recent version of the SOP is at the field location by verifying the SOP number and the revision number with Gas Control when ready to begin work.
- Ensure that SOP steps are followed sequentially per the final approved SOP revision
- Ensure that any changes to the SOP, or sequence changes within the SOP are reviewed and approved by Gas Control prior to their execution.
- Coordinate with Gas Control, as required, when taking regulators stations out of service.

Project Engineering and Design (PE&D) shall be responsible for:

- Support procedure development for inclusion in SOP's for major capital projects - designed by Gas Engineering.
- Assist in SOP development by providing key elements needed for the SOP in major capital projects designed by PE&D and forwarded for review and comment to:
    - I&R
    - Gas Field Operations and Construction
    - Gas Control
- Assist personnel writing final SOP, as requested.

Gas Operations Engineering shall be responsible for:

- Provide minimum operating pressure, temperature and by-pass (jumper) sizing (if required) analyses for SOP's in which the proposed main connection would involve the disruption of gas flow or involvement of a Transmission Main.
- Review and approve SOP's to ensure system continuity.
- Support Gas Field Operations and Construction in the development and review of SOP's for gas system maintenance or expansion work as required.

Field Operations / Construction / Distribution Support (as appropriate) shall be responsible for:

- Develop all SOP's for shutdown or interruption of the gas transmission and distribution systems including but not limited to
    - All live gas main connections for gas main tie-ins
    - Main extensions
    - Service connections that require a full tee tie-in
- Ensure an SOP is approved prior to the start of field excavation, including pipe installation in accordance with ***your company's procedures***
- Review final approved SOP with responsible party overseeing the execution of the work-prior to beginning in the field.

- Prior to executing the SOP, contact Gas Control and request permission to proceed with work in accordance with instruction set forth within.
- Ensure the most recent version of the SOP is at the field location – verify the SOP number and the revision number with Gas Control when ready to begin work.
- Operate and tag system valves as directed by Gas Control during the SOP - including shutdowns and restoration.
- Ensure that any changes to the SOP, or sequence changes within the SOP are reviewed and approved by Gas Control prior to their execution.
- Print a hard copy of the completed SOP, with all GSO notations, and include as part of the Historical Document Package.
- Prepare and perform a final review of Field Historical Documents and submit to Mapping in a timely fashion to update the Mapping System based on actual field as-built drawings.

Gas System Mapping is responsible for:

- Mark the mapping systems in the area of work with the three mapping SOP job statuses' of: "Approved", "Complete", and Quality Controlled ("QC'd")
    - Approved - plot on the system maps the preliminary job after approval by Gas Control.
    - Complete - update system maps to reflect a Gassed-In Status, after completion of the SOP.
    - QC'd - perform a final review of Field Historical Documents and coordinate the updating of the Mapping Systems based on actual field as built drawings.

3. Personal & Process Safety

Personal Safety

All required Personal Protective Equipment (PPE) shall be worn and utilized in accordance with the current National Grid Safety Policy.

Process Safety

If actual work is not scheduled within 90 days of the approved SOP then a follow up review is required prior to commencing work to confirm system changes have not occurred.

Special attention needs to be taken regarding gauging requirements and more importantly the monitoring of gauges during the SOP process.

Personnel must remain aware at all times that conditions may change resulting from changing or abnormal conditions.

Accountability for correctly performing an SOP operation is assigned to the field project manager or responsible person on site.

4. Content

5.1 Administrative Control

a. Technical Training

1) Only technically qualified personnel will be permitted to work within the SOP Process.
2) The method of qualifying is accomplishing by the following:
   i. Successful completion of the “E-Learning Training Module(s)” on SOP System Overview and how to write SOPs – **and**

   ii. Attend a Two Day Overview session at the Corporate Training Center related to properties of Natural Gas and Basic Field Construction Techniques
   or

   iii. Participate in the Operator Qualification Programs for Field Operations and Construction

b. Written Approval

1) Area Managers are required to formally request access to either approve and/or write SOPs for employees under their jurisdiction
2) This Manager will need to attest to the employees qualifications via written document

c. Maintaining Technical Qualifications

Working within the SOP Process - Personnel are required to write SOP periodically at intervals not to exceed 12 months or they will need to re-qualify as per Technical Training and Written Approval above.

5.2 Environmental Considerations

a. Gas Venting

The Company has established a goal to minimize greenhouse gas emissions by minimizing gas vented to the atmosphere during line de-pressurization and purging operations.

1) Gas should be recovered rather than vented when ever possible by de-pressurizing, through a properly designed and approved connection, into a lower pressure system where practical.
2) The SOP shall consider engineering controls to minimize gas venting.
3) Where gas venting is avoided, document estimated volume of gas recovered. I
4) If gas is vented, estimate the volume vented and document appropriately. T

b. Sampling

Environmental sampling (PCB Wipe Test) shall be conducted as required by applicable corporate procedure.

5.3 SOP Requirements

When an emergency shutdown (unplanned) is required as the result of a gas leak, third party damage or other unforeseen circumstance, an SOP is not required. Gas Control shall direct all shutdown operations involved with the unplanned emergency.

SOP's shall be created utilizing an electronic form.

System pressures shall be monitored with pressure gauges at the location of the shut down. During a shut down process, field crews are required take action to prevent the pressures from falling below the minimum shutdown pressure. If gas system pressures on either side of the shutdown area fall below the minimums specified in the SOP - Notify Gas Control immediately.

a. Sectionalizing Valves:

When designing jobs and developing SOP requests when a new gas main is installed across a boundary of a sectionalizing district, ensure that installation of a strategically located valve is included to ensure the integrity on the Sectionalizing District is maintained.

b. Value Position Verification:

When writing an SOP, include steps to verify the position of valves prior to the purging or gas-in operation.

c. Odorant Injection (Pickling):

Pickling shall be conducted as required by applicable corporate procedures.

5.4 Critical Operations

a. Critical operations performed during an SOP are defined as actions that cause gas flow interruption or re-direction of gas flow through an established bypass.

b. Critical operations shall require a Company Supervisor/Field Construction Coordinator (FCC) or competent SOP trained individual as determined by the Supervisor/FCC to be on-site during the execution of the SOP.

c. The following operations shall be considered critical:

1) Hot-taps and/or Flow interruptions are to be performed on critical mains as highlighted on the corporate mapping systems.
2) Any work within 200 feet of a district regulator or take station.
3) Low Pressure flow test and/or bypass.
4) Hot tapping and stopping as a single operation through the use of welded pressure control fittings.
5) High-pressure plastic squeeze off when bypasses are used.
6) Turning of system valves for flow interruptions or abandonment of main.

Once operations have been executed, the presence of the Company Representative is discretionary provided there are no abnormal or emergency conditions present.

5.5 Notifications

a. New SOP's or revisions to SOP's shall be submitted to Gas Control for review and approval at least 48 hours in advance of the scheduled time of the SOP.
b. **Critical Facilities**: Gas Control shall be notified at least 48 hours prior to the start of the SOP when working near Gate Stations, Transmission Mains, Regulator Stations, Power Plants, Large Industrial Customers, LNG Plant, etc.
c. **Mobilization**: The field crew performing the excavation shall notify Gas Control on the same day, prior to beginning excavation.
d. **Flow Interruption**: Gas Control shall be notified prior to interruption of gas flow, to "Request Permission" to start the shutdowns or tie-in operations, and from then on at the direction of Gas Control.

Gas Control shall request the radio number and/or Nextel number of the crew(s) performing the work. Communications tests shall be coordinated/conducted as needed.

e. **SOP Implementation**: Gas Control shall be notified at additional points during the execution of the SOP such as:
   1) Prior to gassing in the new main.
   2) When the first service is tied over onto the new main.
   3) When last service is transferred – Prior to retirement of old main.
   4) When the old main is retired and the SOP is completed.
f. Approved SOP's that have not been executed within 12 calendar months from the date originally approved shall be returned to author for review. If the work is still required, a revised SOP shall be initiated.

If an SOP is discontinued prior to the completion of the work and scheduled to re-start at a later date, the Field Supervisor responsible for successful completion of the SOP shall notify Gas Control of a "Temporary Stop" and estimated date of when work is to start again. Field Supervision shall confirm the interim disposition of all work including an estimated continuation/completion date with Gas Control which will be noted in the next step in the Gas Control comment section. Field Operations shall confirm with Gas Control that both field conditions and system operating conditions have not changed to the extent the original SOP is invalid.

If an SOP is cancelled, Gas Control shall be notified in order to update the outstanding SOP files.

5.6 Gauging Requirements

All procedures require the installation of "*Sufficient Gauges*" to ensure the integrity of the system regardless of system pressure (i.e. low, intermediate, and high pressure).

a. Gauges shall be installed on all operating systems that may be impacted by the work.
b. Gauges shall be installed for tapping operations, bag-off operations, valve operations or any stoppage of gas flow.
c. Gauges shall be installed on both sides of any live gas work area.
d. Pressure gauge readings shall be called into Gas Control at the end of each stoppage of gas flow operation – include the pressure before the stoppage of flow.
e. Gauges shall be monitored for flow interruptions - throughout the scope of work
f. Gauge pressure readings shall be documented and included in the field package.

Once the live gas operation commences and the system stabilizes, crews shall monitor the pressure for an additional 15 minutes (minimum) to ensure the system can handle the stoppage of flow, and then "*Request Permission*" from Gas Control before proceeding with the next steps in the SOP. Gauges shall be continually monitored throughout the scope of the work.

5.7 Bypass Operations

The installation of bypasses is required on jobs - determined by the SOP author, Gas Operations Engineering or Gas Control.

a. Gas Operations Engineering will determine the size and number of bypasses required.
b. Flow stoppage will be monitored with sufficient gauges outside the work area and minimum gas system pressure requirements will be maintained. Call in pressure readings to Gas Control.
c. Low Pressure (LP) bypasses shall be flow tested. A flow test will confirm if the recommended bypass is sufficient.

If the bypasses do not support system pressure - notify Gas Control and proceed to install additional bypasses.

Notify Gas Control if the additional bypasses support system pressure - if not the job will be stopped until further investigation is complete with the input from Gas Operations Engineering.

On Low Pressure Mains; if bypasses are not used, a flow test or pressure recovery test is required in accordance with the applicable procedure (e.g., Standard Flow test procedure for main bag-off low pressure main or equivalent).

On elevated pressure mains; if bypasses are not used, a pressure recovery test is not required, but is recommended based on regional practice. Gauge requirements still apply.

5.8 Flow Stoppage Without Bypass

In order to stop flow of gas without the use of a bypass, the pressures on both sides of flow stoppage shall be monitored by the installation of sufficient gauges.

a. Prior to the stoppage of flow, closing of a valve, bagging etc, gauges shall be checked and minimum system pressures shall be ensured before SOP proceeds.
b. Once the live gas operation commences and the system stabilizes, crews shall monitor the pressure for an additional 15 minutes (minimum) or longer if noted on SOP to ensure the system can handle the stoppage of flow, and then request permission from Gas Control before proceeding with the next steps in the SOP. Gauges shall be continually monitored throughout the scope of the work.

5.9 Flow Test

a. Upon stopping the flow of gas with the use of a flow test, the pressures on both sides of the flow stoppage shall be monitored by the installation of sufficient gauges in accordance with appropriate procedures (e.g., Standard Flow test procedure).
b. Gauges shall be utilized prior to the stoppage of flow.
c. Closing a valve, bagging, etc; both sides of work area shall be monitored and minimum system requirements shall be maintained.
d. Pressure readings shall be called into Gas Control.

If the Flow Test fails, notify Gas Control and commence bypass operation in accordance with the (e.g., Standard Flow test procedure).

5.10 Valve Tagging Requirements

a. Prior to operating permanently installed system valves as part of an SOP, permission shall be obtained from Gas Control. If valves are operated as part of an SOP, a “Do Not Operate Tag” shall be attached to prevent inadvertent operation and to protect the safety of personnel and the integrity of the job.
b. When developing SOP’s, all organizations are to evaluate the process to determine if system valves shall be operated

5.11 Valve Tagging Process

a. When GAS CONTROL directs the authorized employee to operate a valve, a “Do Not Operate Tag” is required and that employee shall record on the tag the required information: Refer to Sample Valve Tag (Attachment 1: Sample Valve Tag)
b. The authorized employee or Field Supervisor shall be responsible to remove Tags as directed by Gas Control as outlined in the SOP. Authorized employees removing the tag do not have to be the same employee who attached the tag. This tag shall be kept on file along with other project documents.

No tag shall be removed without direction from Gas Control

When non-company personnel are performing work, an authorized Company employee is responsible to call in all the steps of the SOP to Gas Control and to direct the attachment of the tag when authorized by Gas Control.

c. Only under the direct supervision of a Company employee shall Non-Company personnel be permitted to apply/remove tags

d. Valves installed during construction, and left in the closed position, also require the installation of a “Do Not Operate Tag” and permission to operate prior to the main being gassed in. Valves left in open position do not require tagging.
e. Return the tags and file it along with other associated project documents.

5.12 Guidelines for Taking a regulator Out of Service

a. Outage Authorization:
   1) Prior to taking the station out-of-service:
      i. Gas Control Operator - verify station outage temperatures and current restrictions on the system.
      ii. I&R - notify and receive permission from Gas Control

Refer to the Gas Operations Engineering Temperature Restriction Chart to determine the minimum outage temperature. For issues relating to the span between current temperature verses chart temperature, contact Gas Operations Engineering for verification. For areas that do not have a Gas Operations Engineering Temperature Restriction Chart and the work is planned, the I&R Supervisor and Gas Control shall have obtained through Gas Operations Engineering, a station outage analysis that contains the associated restrictions determined by that analysis. If the shutdown is an emergency, Gas Control shall initiate contact with Gas Operations Engineering, who shall then run a station outage analysis.

Review current system outage work on the gas system in the area. If a current system outage exists, contact Gas Operations Engineering to perform a revised station outage analysis.

b. Regulator Station Outage and Monitoring:

The station outlet pressure shall be monitored by Gas Control via SCADA (where applicable) and by the on-site I&R Crew using a calibrated gauge. The pressure shall be monitored for a minimum period of 15 minutes following stabilization of pressure to ensure that the system can handle the regulator station shutdown.

   1) Prior to isolation of the regulating station:
      i. I&R Crew -setup and monitor the station outlet pressure using a calibrated gauge that best matches the pressure range to be monitored.
      ii. I&R - notify Gas Control of the current outlet pressure prior to lowering the station’s outlet pressure.
      iii. Gas Control - verify reading against SCADA outlet pressure of that station, where available.

c. Outlet Pressure Stabilization:
   1) I&R crew - lower the set point of the controlling regulator (2nd stage where applicable) to shut the station flow down while monitoring the outlet pressure until it stabilizes.

STOP

Do not let the outlet pressure drop below the applicable pressure restriction set by the Gas Control Operator.

2) I&R crew - close the inlet valve to the controlling regulator (2nd stage where applicable), and any associated control line valves per the applicable sequence based on the operating characteristics of the installed regulators. Parallel run stations shall have both runs valved off including the associated control lines.
   i. Gas Control - record valve/s #'s (where applicable).
3) I&R crew - If the pressure holds above the applicable pressure restriction and it is stable, record the stabilized outlet pressure and communicate it to Gas Control.
   i. Gas Control -record the time and outlet pressure reading from field and if applicable, the SCADA outlet pressure reading.

If the pressure does not hold above the applicable pressure restriction or it is not stable, the station can not be shut down and the outlet pressure shall be restored to its starting value.

   ii. I&R crew - notify Gas Control and the appropriate I&R Supervisor that the station can not be shut down.

d. Station Isolation:

I&R Crew - ensure that at all times the station outlet pressure is being monitored by a gauge and that they are not looking at a trapped gas pressure due to the closing of any valve.

1) Gas Control - record time of main valve/s closure/s.
2) For stations with SCADA outlet pressure monitoring:

I&R Crew - ensure that at all times, the station outlet pressure transmitter is not locked in by any closed valve and the station shall be left in a state such that Gas Control can continuously monitor the station system outlet pressure.

3) Stations being taken out of service for extensive work either at the station or out in the system that makes SCADA monitoring of the station impracticable, may have the SCADA pressure transmitters taken out of service after the minimum 15 minute monitoring period.
4) Proceed to monitor the station outlet pressure for minimum of 15 minutes.

e. Outlet Pressure Monitoring 15 Minute Minimum:

1) I&R Crew - monitor the station outlet pressure for a minimum of 15 minutes and contact Gas Control with ending reading.
2) Gas Control - record the time and outlet pressure reading from field and if applicable, the SCADA outlet pressure reading.

The station outlet pressure should not drop below the recorded stabilization pressure. If at any time during this minimum 15 minute monitoring period, the station outlet pressure drops or it becomes unstable, the station shall be turned back on and set to the initial outlet pressure setting.

3) If the outlet pressure does not stabilize or drops during the minimum 15 minute monitoring period:
   i. I&R crew - remain on-site and complete the work at the station immediately.

    ii. If the station is being taken out of service for work out in the system, that work can not proceed until the source of the problem is found.
    iii. Gas Control - notify both the I&R manager and the respective field maintain manager

5.13 Pressure Schematic Upgrade notification

a. In the SOP application there is a Y/N Checkbox to indicate whether the SOP work requires an update to the Corporate Pressure Schematic.
b. Reasons for triggering a schematic upgrade include:
    1) Regulator Station addition
    2) Regulator Station retirement
    3) Change to system MAOP on inlet to regulator station (new supply or system uprate/derate)
    4) Change to system MAOP on outlet of regulator station (system uprate/derate/integrate)
    5) Connect single feed system to another system at same MAOP
    6) Addition of a Source Point (pipeline, LNG, biogas, CNG, etc.) *Retirement of a Source Point (pipeline, LNG, biogas, CNG, etc.)
    7) Change to MAOP of a Source Point
    8) Connect systems with multiple feeds to other systems with multiple feeds
c. SOP writers and reviewers have the option of checking yes or no throughout the SOP process.
    1) Upon Completion of the SOP, an email will be triggered by the SOP to the Pressure Schematic Review Team.
    2) If a schematic update is needed, members will update the pressure schematic and store on the records server.

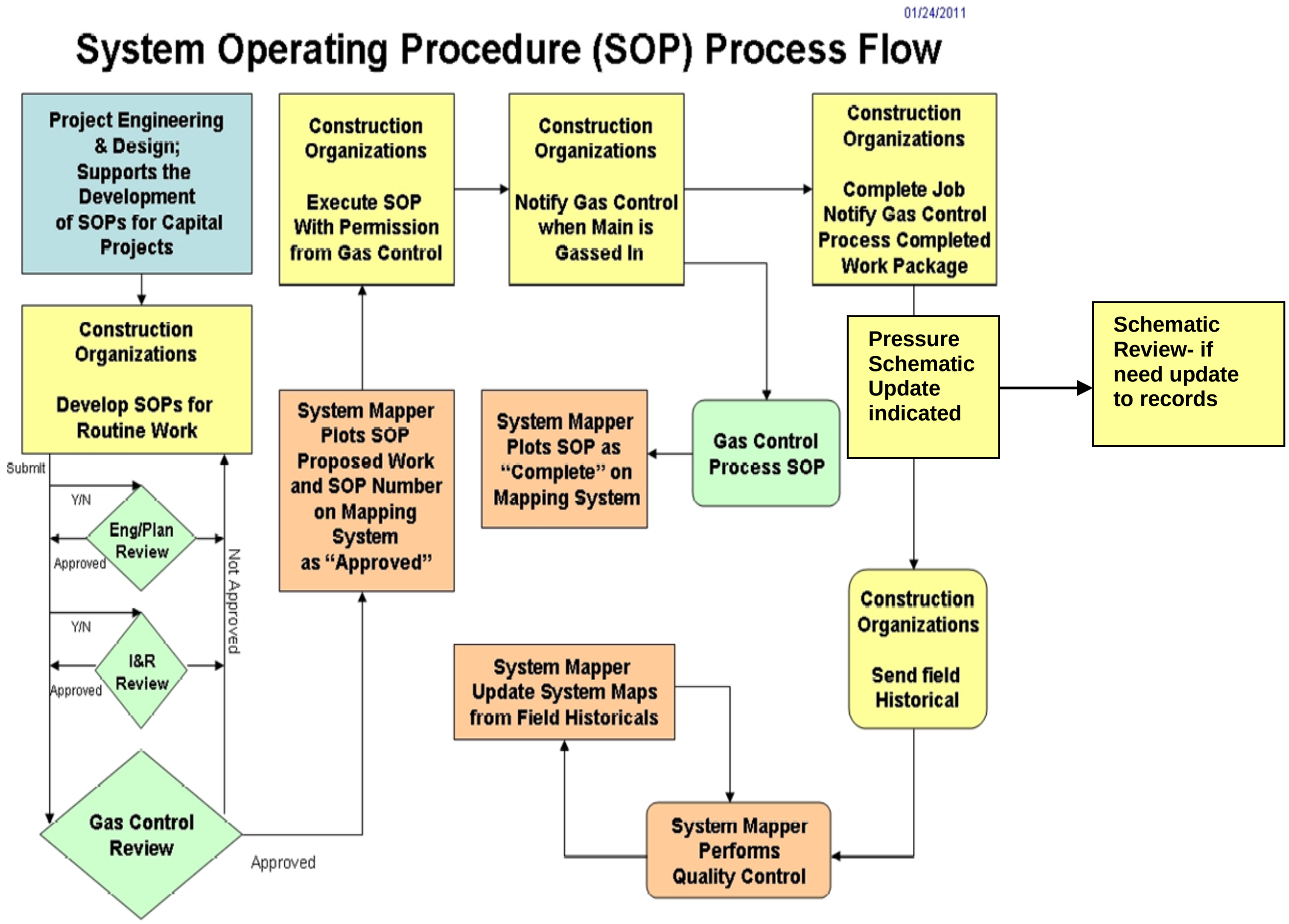
6. Attachments

<u>Attachment 1</u>: Sample Valve Tag

<u>Attachment 2</u>: System Operating Procedure - SOP Process Flow Chart

Attachment 1: Sample Valve Tag

Attachment 2: System Operating Procedure - SOP Process Flow Chart



Appendix 8

Sample Pre-Startup Safety Review Checklist

SAMPLE Pre Start-up Safety Review (PSSR) Procedure

INTRODUCTION

A Pre Start-Up Safety Review (PSSR) examines a new or modified process safety asset to ensure that it has been constructed as per the approved design, that all safeguards and protective devices have been calibrated and tested and that it is safe to operate as per the details contained in this procedure. The requirement for a PSSR also applies to assets that have been out of service for an extended period as a result of repair or temporary discontinuation of use.

The requirement to perform a PSSR is part a Process Safety Management System (PSMS) and a corresponding approach to assess major hazards. In this context, major hazard is defined as an incident that leads to the loss of control in the operation of an asset resulting in significant loss of containment of a dangerous substance leading to serious danger to people or the environment onsite or offsite.

This procedure applies to Company defined Major Hazard assets, including:

- Compressed Natural Gas (CNG);
- Gas Transmission and facilities operating at 125 psig and above;
- Power Generation;
- Liquefied Natural Gas (LNG);
- LNG Trucking.

However, this procedure can also be broadly applied to the management and operation of other Comapny non major hazard assets, including ***Gas Distribution Regulator Stations.***

PURPOSE

This procedure defines the minimum standards to be adopted across Company assets for Operational Readiness by setting requirements to ensure that there is a systematic process to verify that assets are in a safe condition and that personnel are appropriately prepared before start-up of new assets or before returning assets to normal operation following a prolonged outage, or modification where the process safety information of the asset has changed.

ACCOUNTABILITY

The Corporate Process Safety Department is accountable for maintaining this procedure.

TRAINING

PSSR is a Process Safety competency. Each involved business is responsible for identifying its process safety roles and the level of competency required for each role in order to successfully implement the PSSR program for their areas in compliance.

Business Areas are responsible to ensure their employees are trained on this corporate procedure and any additional business specific guidance in order to implement this procedure.

Table of Contents

1 OVERVIEW

A PSSR determines that process safety assets are ready to be safely placed into service. PSSR evaluates not only the condition of the asset after construction, but also evaluates the asset from an operational, maintenance and emergency procedural perspective in the form of checking for written procedures and personnel training before the asset is placed into service. These evaluations ensure that instructions address safe operating issues, and that personnel are trained on its safe operation and are aware of any associated process safety hazards.

PSSR applies to new process safety assets, and to existing ones that have been modified so that the asset's Process Safety Information (PSI) has changed. A PSSR performed on a modified unit ensures that the modifications have not introduced any unforeseen hazards into its operation, that all safety issues have been incorporated in its operating instructions, that all personnel have been trained in any new or modified procedures, and that they are aware of the changes and potential new risks.

Finally, PSSR is also applied to assets that have been out of service for an extended period of time such that the integrity of the asset may have been compromised or it is not certain that all operational and safety equipment is fit for purpose. After an extensive downtime, the asset must be reviewed to ensure that it is in a safe operating condition, and that the personnel responsible for the asset are refreshed on its safe operation.

2 DEFINITIONS

Consequences – The result of the hazard scenario. Consequences of concern are process safety issues, large scale environmental events, property or equipment damage affecting use or long-term reliability, and physical injury to employees, contractors and the public.

Hazard Scenario – A specific, unplanned event or sequence of events that cause an undesirable consequence to safety or to the environment.

Likelihood – The qualitative probability of the hazard scenario occurring, given the safeguards that are currently in place. Current performance of safeguards and Probability of Failure on Demand are taken into account.

Management of Change (MOC) – Process to ensure that the changes in design or scope after a PHA is completed are analyzed from a risk perspective to incorporate any impact to risks or hazard scenarios.

Operational Readiness – Ensuring that new commissioning of assets and shutdown of assets and processes are in safe conditions to be started / restarted through types of Pre Start-up Safety Reviews (PSSR) which factors in any work performed while the equipment was shut down.

PSSR Business Lead – The individual knowledgeable with the design requirements of the new asset or modification of the existing asset, to ensure it has been constructed or modified per the approved design and is safe to operate.

PSSR Coordinator – The PSSR Coordinator is the individual responsible for coordinating PSSR activities for a given facility or business. The PSSR Coordinator reviews the PSSR Checklists to ensure that they are filled in with the desired quality of information, and for collating information to measure, track and manage the execution of the PSSR process.

Process Hazard Analysis (PHA) – Organized effort to *identify* and *analyze* the significance of hazardous situations associated with a process or activity to aid management in making critical safety decisions (also known as HIRA – Hazard Identification, Risk and Analysis).

Process Safety Information (PSI) – Information on the hazards of flammable, combustible, or toxic substances used or produced by the process, information pertaining to the technology of the process, and information pertaining to the equipment in the process.

Risk – A measure of injury or environmental damage in terms of both the likelihood and severity of the hazard scenario.

Risk Ranking – The product of severity and likelihood used to evaluate risk.

Severity – Severity is the worst case consequence of the particular hazard scenario and assumes that safeguards have failed.

Shall – Indicates a mandatory requirement.

Should – Indicates a best practice and is the preferred option. If an alternative method is used then a suitable and sufficient risk assessment shall be completed to show that the alternative method delivers the same or better level of protection and results.

Toxic Material – Any item or agent (biological, chemical, radiological, or physical), which has the potential to cause harm to humans, animals, or the environment, either by itself or through interaction with other factors.

3 PROCEDURE

3.1 Preview and Practical Advice for performing a PSSR

3.1.1 Each facility or business shall have a systematic process for checking operational readiness and the integrity of systems before they are brought into service.

3.1.1.1 The minimum requirements for this process shall include:

- Construction and equipment shall be verified to be in accordance with design specifications for new or modified facilities;
- Process control, emergency shutdown and safety systems shall have been tested and found to be functioning as designed;
- Equipment shall be properly appropriately isolated from other systems not yet ready for start-up;
- Equipment shall be properly maintained, checked and be ready for service;
- Equipment and equipment configuration including valve positions shall have been verified to be released to operations and ready for start-up;
- Adequate safety, operating, maintenance and emergency procedures are in place and training of employees involved in these activities shall have been completed prior to putting the assets into service;
- Start-up decisions shall be based on the results of readiness evaluations rather than operational and economic pressures;
- Checks and verification shall be carried out by competent personnel and recorded by the business as part of the PSSR;
- Businesses shall have a defined criterion for categorizing and handling identified issues and outstanding work items;
- Completed checks and verifications shall be reviewed, approved and accepted by specific levels of management defined by the business as appropriate to the magnitude of risk.

3.1.2 A PSSR shall be performed before the start-up of a new or significantly modified facility is authorized.

3.1.3 The individual responsible for the operation of the new facility or modification shall use the following logic to determine when a PSSR is required:

3.1.3.1 A PSSR **IS** required if the modifications to a facility are significant enough to require a change in the asset's Process Safety Information (PSI).

3.1.3.2 A PSSR **IS NOT** required for facilities that have been modified so slightly that process safety information (PSI) does not change.

3.1.4 For any modified assets or facilities, the **Management of Change (MOC) Procedure [PS-02-02]** requirements must be satisfied before start-up.

3.1.4.1 The MOC requirements do not take the place of or eliminate the PSSR.

3.1.5 For new assets or facilities, a Process Hazard Analysis (PHA) must be performed as part of the design phase before start-up and in accordance with the **Process Hazard Analysis (PHA) Procedure [PS-00-01]**.

3.1.5.1 The PHA does not take the place of or eliminate the PSSR.

3.1.5.2 The PSSR team must verify that all of the PHA recommendations required before start-up have been implemented or resolved before the facility can be judged safe to operate.

3.1.6 An appropriate PSSR Checklist shall be used based on the type of construction, maintenance or outage work recently performed.

3.1.7 Reviews should be commensurate with the complexity and level of risk introduced by the new asset or modification.

3.1.8 The PSSR Business Lead will evaluate the extent of the modification or new facility and determine the appropriate PSSR approach to use.

3.2 Completing the PSSR Checklist

3.2.1 The PSSR Business Lead shall identify the need for a PSSR.

3.2.2 The PSSR Business Lead shall determine the appropriate PSSR Checklist to use.

3.2.3 The PSSR team shall perform a physical review of the asset or facility just before start-up to confirm that all related requirements have been met before the process is initiated.

3.2.4 The PSSR team shall identify issues which shall be corrected **BEFORE** start-up and issues which can be corrected **AFTER** start-up.

3.2.4.1 Decisions for categorizing which issues shall be corrected either before or after start-up should be based upon the following logic.

3.2.4.1.1 Issues that shall be resolved BEFORE start-up:

- Deficiencies that could cause or result in a major accident (one that leads to the loss of control in the operation of an asset resulting in significant loss of containment of a dangerous substance leading to serious danger to people or the environment onsite or offsite).

- The process cannot be safely started or operated until these issues are corrected.

3.2.4.1.2 Issues that can be resolved AFTER start-up:

- Issues that do not affect the safe start-up or operation of a unit but that, if corrected, enhance its process safety.

3.2.5 All members of the PSSR team shall review and sign the PSSR form to confirm the asset or facility is safe for start-up.

3.2.6 A Manager (or higher) in the business that operates the asset shall do the final sign off only after all Category A action items are completed. This indicates that it is safe for start-up.

3.2.7 Submit the completed PSSR Checklist (including checks and verifications) to the asset owner and obtain approval by Manager (or higher) to start-up the asset.

3.3 Develop Action Item List

3.3.1 The action item list should be reviewed when the PSSR has been completed.

3.3.1.1 Action Items shall be (a) clearly documented, (b) assigned to a specific individual who is capable of addressing them.

3.3.1.2 The PSSR Business Lead shall assign an individual owner as well as appropriate resources and a target completion date for all Action Items coming from the PSSR.

3.3.1.3 The PSSR Business Lead is responsible to ensure the Action Items are tracked through to completion and completed on time.

3.4 Continuous Improvement

3.4.1 The businesses shall review their PSSRs to identify lessons learned and ways to improve their process.

3.4.2 Where there is common equipment, these should be shared to foster continuous improvement across the Company.

3.4.3 The business shall appoint a PSSR Coordinator to ensure proper functioning of the PSSR program.

3.4.4 The PSSR Register shall be used to track the status of all initiated safety reviews.

3.4.5 The business shall develop and monitor leading and lagging Key Performance Indicators (KPI) to monitor the effectiveness of the PSSR program.

3.5 Responsibilities

3.5.1 The PSSR procedure shall be applied by a team.

3.5.2 The PSSR team shall consist of at least two (2) people:

3.5.2.1 As many team members as necessary should be selected to ensure complete review and the safe operation of the asset.

3.5.3 A meeting should occur in which the team works in a discussion-style format to conduct the PSSR.

3.5.4 The responsibilities of the PSSR Business Lead include, but are not necessarily limited to:

- Form and organize team meetings based on the business input;
- Lead meetings in accordance with applicable ground rules (below);
- Introduce and ensure team understanding of motivation and application of procedure;
- Guide discussion during the assessment and keep team on task;
- Gather and update applicable process safety information (PSI);
- Complete, document and file results of the PSSR;
- Organize and plan field inspections as required by the complexity of the project.

3.5.5 The responsibilities of the PSSR Coordinator include, but are not necessarily limited to:

- Perform or support the role of the PSSR Business Lead for more complex reviews;
- Periodically review selected PSSR Checklists, action items and associated documentation for accuracy and completeness.

3.5.6 Applicable ground rules for the team application of this procedure:

- All suggestions and contributions carry equal weight;
- Online problem solving, designing, or redesigning should be avoided;
- One (1) person talks at a time;
- No overt attempts to influence the opinion of any other team member.

3.6 Documentation and Record Retention

3.6.1 The PSSR and associated Process Safety Information (PSI) shall be documented and retained in accordance with internal and external document retention policies and regulations.

3.6.2 The PSSR, Action Items and documentation showing how the Action Item was closed shall be stored by the PSSR Business Lead in the **Pre Start-up Safety Review (PSSR)**

folder for their business in the **Process Safety Risk Assessment Filing Cabinet** (SharePoint site) linked to the SHE website.

3.6.3 Action Items rejected shall have documentation supporting reasons why it is justifiably declined and how adequate safety is provided in an alternative measure.

3.6.4 Results of the PSSR shall be proactively communicated and made available to all involved employees and contractors by the Business Lead.

3.6.5 Records for the PSSR shall be submitted by the PSSR Business Lead to the asset owner upon completion and remain available for the life of the organization.

3.6.6 The PSSR shall be conducted using the Company approved tools.

4 REFERENCES

List Company Specific References

5 APPENDICES

5.1 Appendix A: Example Pre Start-up Safety Review (PSSR) Checklist

Pre-startup Safety Review Checklist	
Part of the Business / Region:	
Involved Equipment:	
Project Number:	

Signatures below indicate acceptance that the equipment or project is safe and satisfactory to start-up with the exceptions noted.	
Engineering	**Date**
Maintenance	**Date**
Instrumentation and Controls	**Date**
Project Management	**Date**
Operations	**Date**
PSSR Business Lead	**Date**

Checklist Item No.	**Action Item Details (reference category / item no.)**		**Action Item Owner**	**Due Date**
Category A* Action Items** – *to be completed* ***BEFORE *authorization and start-up*				
	A.1			
	A.2			
	A.3			
Category B* Action Items** – *to be completed* ***AFTER *start-up*				
	B.1			
	B.2			
	B.3			
Sign below only when all punch list "Category A" Action Items are completed				
Authorized:	*Plant / Equipment Operations Signature (Manager or higher):*		**Date**	

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
1.0 GENERAL SAFETY					
1.1	Has adequate and appropriate *PPE* (Personal Protective Equipment) been specified in the Work Procedures and/or Standard Operating Procedures.	Operation			
1.2	Has the PPE been provided?	Operation			
1.3	Have the PPE users been trained in the use of the PPE?	Operation			
1.4	Are all of the applicable Work Permit Procedures (Confined Space Entry, Lock Out/Tag Out, Hot Work, etc.) for this equipment in place?	Operation			
1.5	Have the Operating, Maintenance, and Supervisory personnel been properly trained on the Work Permit Procedures?	Operation			
1.6	Has any fire protection systems been inspected and approved for use by the internal responsible party for fire protection or the external insurance company?	Proj Mgt			
1.7	Are all of the applicable Operating Permits up to-date and approved?	Proj Mgt			
1.8	Review lessons learned from previous PSSRs on similar equipment or processes	All			
2.0 MACHINERY/EQUIPMENT SAFETY					
2.1	Has all access to dangerous moving parts, or danger zones created by the equipment, been prevented by the provision of the correct guards, interlocks (both safety & non-safety) and/or barriers?	Proj Mgt			
2.2	Is the equipment provided with a clearly identified means to securely isolate it from *ALL* energy sources?	Operation			
2.3	Has safe access been provided to the equipment that requires operator and calibration and maintenance personnel access for normal operations, adjustments, service, calibration, maintenance, or repair?	Operation			
2.4	Is the equipment provided with the properly identified *START/STOP* and *EMERGENCY* controls that are positioned for safe operation without hesitation, or loss of time, and without ambiguity?	Operation			
3.0 PROCESS SAFETY – PROCESS TECHNOLOGY					

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
3.1	Are up-to-date Safety Data Sheets (SDS) available if involved?	ENGR			
3.2	Have the hazardous effects of inadvertent mixing of different materials been considered if relevant to the process?	ENGR			
3.3	Has the design basis and drawings been documented or updated to include new and changed equipment including all safety protective equipment and devices so that they can serve as as-built documentation for the PSSR? Note: this is not meant to address record management issues under RCS10.	ENGR			
3.4	Have calculations been done to determine the size and type of safety protection needed from worst case credible asset related failures?	ENGR			
3.5	Do the calculations take into account potential external fire exposures (i.e. Are relief valves sized to handle heat from external fire)?	ENGR			
3.6	Are all relief devices designed to vent to safe locations away from potential employee exposure?	ENGR			
3.7	Are there isolation valves designed that if closed, will inhibit the operation of pressure relief devices?	ENGR			
3.8	If yes, are there control plans to insure that the isolation valves cannot inhibit the operation of the pressure relief devices.	Operation			
4.0 PROCESS SAFETY – MANAGEMENT OF CHANGE (MOC)					
4.1	Has a management of change form been prepared and approved for the new design project?	ENGR			
4.2	Has a management of change form been prepared and approved for the new design project, if this is a design change to existing equipment?	ENGR			
4.3	Are all action items, arising from the MOC, that were deemed necessary for start-up, complete?	Proj Mgt			
4.4	Has a management of change form been prepared and approved for applicable construction changes to an approved design?	Proj Mgt			
5.0 PROCESS SAFETY – PROCESS HAZARDS ANALYSIS (PHA)					

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
5.1	Have project PHAs been approved by the Process Safety governing body?	ENGR			
5.2	Are all action items, deemed necessary from the PHA related to start-up been completed in accordance with **Process Hazard Analysis (PHA) Procedure**?	Proj Mgt			
5.3	Are all action items, deemed necessary from the LOPA related to start-up been completed in accordance with **Layer of Protection Analysis (LOPA) Procedure**? If applicable.	Proj Mgt			
5.4	Are all action items, deemed necessary from the QRA related to start-up been completed in accordance with **Quantitative Rias Assessment (QRA) Procedure**? if applicable.	Proj Mgt			
5.5	Has Facility Siting been completed for this asset in accordance with **Facility Siting Procedure**? If applicable.	Proj Mgt			
6.0 PROCESS SAFETY – QUALITY ASSURANCE					
6.1	Have checks and inspections been made to ensure that critical equipment is installed properly and is consistent with design specifications and vendor's recommendations (for example, alarm and interlock (safety & non-safety) tests; equipment alignment and service to process inter-connections)?	Proj Mgt			
6.2	Have inspection reports, covering fabrication, assembly, and installation, been completed in accordance with the project's procedures, work methods and any applicable quality assurance plans?	Proj Mgt			
6.3	Does the construction meet the design specifications and the drawings?	Proj Mgt			
6.4	**Have the following documents been provided and approved:**				
6.4.1	Instrument indexes and instrument loop diagrams?	Proj Mgt			
6.4.2	A tabulation, including settings, of interlocks (both safety & non-safety) and trips (hardwire and software), process alarms and permissive descriptions?	Proj Mgt			
6.4.3	As-built drawings covering P&IDs, electrical, piping, and mechanical?	Proj Mgt			
6.4.4	Data sheets for pressure equipment built to ASME or equivalent codes?	Proj Mgt			

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
6.4.5	Data sheets for over pressure protection setpoints and initial testing?	Proj Mgt			
6.4.6	Date pressure test has been complete?	Proj Mgt			
6.4.7	Welder certification?	Proj Mgt			
6.4.8	Non-destructive test (NDT) or examination (NDE) certifications?	Proj Mgt			
6.4.9	Electrical certification for classified areas?	Proj Mgt			
6.4.10	Enter additional relevant documents if needed.	Proj Mgt			
6.5	List all commissioning tests performed (for example, pressure, leak tests, meggaring, etc.)	Proj Mgt			
7.0 PROCESS SAFETY – MECHANICAL INTEGRITY					
7.1	Have maintenance procedures been developed and approved by the business?	MAINT			
7.2	Have maintenance personnel been trained in maintaining the equipment?	MAINT			
7.3	Are their adequate inventories of critical spare parts?	MAINT			
7.4	**Have inspections and tests, including regulatory requirements for the following equipment been included in a maintenance schedule:**				
7.4.1	Pressure vessels and storage tanks?	MAINT			
7.4.2	Pressure relief systems, vent systems, and devices?	MAINT			
7.4.3	Critical controls, interlocks (both safety & non-safety), alarms and instruments?	MAINT			
7.4.4	Emergency devices (including shutdown systems and isolation systems)?	MAINT			
7.4.5	Fire protection equipment?	MAINT			
7.4.6	Piping systems (incl. Components, for example, valves, excess flow valves, expansion bellows) in critical service?	MAINT			
7.4.7	Emergency alarm and communication system?	MAINT			
7.4.8	(list any other critical equipment)	MAINT			
8.0 PROCESS SAFETY – OPERATING PROCEDURES AND SAFE WORK PRACTICES					
8.1	Have standard operating procedures been prepared/updated and approved by the business?	Operation			

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
8.2	Do the operating procedures cover: Initial start-up? Normal start-up? Normal operations? Normal shutdowns? Emergency operations including emergency shutdowns? Start-up after emergency shutdowns? Start-up following turnarounds/prolonged shutdowns? High hazard non routine operations?	Operation			
8.3	Have Operations been trained in operating procedures?	Operation			
9.0 PROCESS SAFETY – TRAINING AND PERFORMANCE					
9.1	Has specific process (or job task) training been given to Operations personnel?	Operation			
9.2	Have training records been updated?	Operation			
10.0 PROCESS SAFETY – CONTRACTOR SAFETY					
10.1	Have contract personnel been adequately trained in applicable awareness, maintenance, and evacuation procedures?	Operation			
11.0 PROCESS SAFETY – PROTECTIVE DEVICES: INTERLOCKS, ALARMS and SIS					
11.1	Did design require a Safety Instrumented System (SIS) in accordance with ANSI / ISA 84? If yes, was the SIS completed in accordance with internal SHE procedures and Risk Control Standards?	ENGR			
11.2	Did the loop testing confirm that the alarm/interlock (safety & non-safety) action proved, under all conceivable failure conditions, to be fail-safe and performed as per design?	ENGR			
11.3	Has an interlock/critical alarm procedure for testing, through to the final element, been prepared and reviewed/authorized by a competent person for each new or upgraded control system?	ENGR			
11.4	Has the equipment software in the field been verified (for example, logic drawings, schematics, sequence/batch descriptions) to ensure that it is the version specified in the design?	ENGR			
11.5	Have alarms been rationalized?	ENGR			
11.6	Have alarm response sheets been completed?	ENGR			

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
11.7	Do you have an appropriate procedure to ensure that your software is protected (for example, routinely archived, key/password protected, etc.)?	ENGR			
11.8	Has all software been properly validated and tested?	ENGR			
11.9	Have all process and safety alarms and shutdowns been set and tested to be in accordance with Engineering design?	Proj Mgt			
11.10	Have all SIS equipment been added into inspection and maintenance plans?	MAINT			
11.11	Have all SIS equipment been added to the asset risk register?	MAINT			
11.12	Have all protective devices been added to the protective device asset register.	MAINT			
11.13	Have all protective and SIS devices been added to the inspection, testing and maintenance workplans.	MAINT			
12.0 PROCESS SAFETY – EMERGENCY ARRANGEMENTS					
12.1	Have Emergency Procedures been prepared and relevant personnel trained?	Operation			
12.2	Are Emergency Evacuation plans available with key roles identified and drill completed to validate functionality of plan and assembly plan?	Operation			
12.3	Is emergency lighting adequate?	Operation			
12.4	Is sufficient Respiratory Protective Equipment, such as Escape Sets or Self-Contained Breathing Apparatus (SCBA) required and if so available with personnel certified and trained in its usage?	Operation			
12.5	Are relevant key external stakeholders aware of project?	Operation			
13.0 PROCESS SAFETY – FIELD VERIFICATION					
13.1	Are all pipelines labeled?	Proj Mgt			
13.2	Are all electrical switches, disconnects, MCCs, control panels, cables labeled?	Proj Mgt			
13.3	Are electrical conduits sealed in accordance with code requirements?	Proj Mgt			
13.4	Are wall penetrations adequately sealed?	Proj Mgt			
13.5	Has all scaffolding and construction equipment been removed?	Proj Mgt			
13.6	Is housekeeping acceptable to allow a start-up?	Proj Mgt			

PSSR ITEM No.	CATEGORY / ITEM TO ASSESS	Owner	Completed (Y/N/NA)	Owner initials	Inspection Date
13.7	Equipment and equipment configuration including valve positions shall have been verified to be released to operations and ready for start-up	Proj Mgt			
13.8	Does initial startup of asset include a named individual responsible for periodically checking performance of asset for first 48 hours? Insert individual's name here:	Operation			
14.0 PROCESS SAFETY – HUMAN FACTORS					
14.1	Have a new safety critical activity (SCA) procedure been developed?	ENGR			
14.2	Have the new SCA procedure been categorized in accordance with **Safety Critical Activity Procedure Categorization and Risk Ranking Tool**?	ENGR			
14.3	Have the new SCA procedure been assessed for Human Errors in accordance with either of the following: **Four-Question Analysis Procedure, Hierarchical Task Analysis (HTA) Procedure, Eight Guideword Analysis Procedure**?	ENGR			
14.4	Was a Human Factors Basis of Design (BOD) completed for this asset in accordance with **Safety in Design Specification for Incorporating Human Factors**?	ENGR			

Appendix 9

Sample Change Control Procedure for Construction Projects

Change Control Procedure for Construction Projects

1. Purpose

This procedure sets out the administrative requirements, responsibilities and approval process for field changes to construction projects to account for budget, schedule and scope changes.

a. The objective of this procedure is to ensure that:
   1. Significant changes in scope to construction projects receive appropriate review and approval prior to being implemented. These include but are not limited to changes resulting from:
      a. Field Conditions
      b. Scope Change
      c. Design Change
      d. Personal and Process Safety Issues
   2. Construction project changes are identified, recorded and approved. The Change Control Procedure is implemented from the time a change is identified through implementation of the change.

b. This procedure applies to the following projects:
   1. All Managed Projects (Including Complex Design Projects)
      i. Complex Design Projects Category 3 changes prior to issuance of construction drawings.
      ii. Complex Design Projects after construction drawings have been issued: As specified in section 5.1
   2. All standard Projects (Non-complex Design Projects) with estimates exceeding $100,000

Exceptions to this procedure to accommodate business or operational needs shall be approved by the Engineering Executive with responsibility for the Construction Process and documented on the Project Change Order Form (Attachment 1)

This procedure does not cover changes to the approved detailed gas design drawings or established gas work methods, policies and construction standards/drawings. Changes to detailed Project Engineering drawings must be referred to Project Engineering for review and approval and may require a Management of Change (MOC) in accordance with <u>Process Safety Management of Change</u> Protocols(Reference Section 3). Changes to Gas Work Methods, Policies and Construction Standards are governed by XXXXXX Governance Policy and must be reviewed and approved prior to field Implementation.

2. Responsibilities

<u>Manager of Complex Construction, Project Manager or Regional Construction/Field Ops Manager</u> or designee shall be responsible for:

- Initiating Change Orders as necessary when not initiated by others
- Ensuring approvals are obtained as necessary.
- Advising Process Director or Regional Construction Director of any impact of Change Orders on project design and schedule.

- Obtaining necessary documentation from contractors on Change Orders.
- Approving non-complex design project Category 1 and Category 2 Change Orders not approved by Engineering or Supervisor/Field Construction Coordinator.
- Submitting for approval complex design project Category 1 and Category 2 Change Orders to Project Engineering & Design as required.
- Initiating, as required, reviewing and submitting Category 3 Change Orders for review and approval to Network Strategy and Regional Construction Directors.
- Maintaining Project Change Order Forms and Change Control Log in the Work Order/Project Folder and or project electronic data base

<u>Construction & Maintain Supervisor / Field Construction Coordinator (FCC)</u> or designee shall be responsible for:

- Initiating Project Change Order Forms for Category 1, 2 and 3 Change Orders as necessary.
- Completing Contractor Information, Contract Information, Change Order Category, Project Accounting and Change Notification sections of Change Order Form (Attachment 1)
- Notifying the Originating Organization, Resource Planning, Gas Construction/Maintenance, Project Management/Engineer of the requested change and record on the Change Order Form
- Approving non-complex design project Category 1 and Category 2 Change Orders that do not deviate from Construction Standards/Drawings and Gas Work Methods.
- Submitting for approval complex design project Category 1 and Category 2 Change Orders to Project Engineering & Design.
- Submitting Category 3 Change Orders for review by Process Manager, Manager of Complex Construction, Project Manager or Regional Construction Manager
- Maintaining Project Change Order Forms and Change Control Log in the Work Order/Project Folder and or project electronic data base

<u>Project Engineering & Design, Project Management, Complex Construction, Main/Services/Replacement Engineering, Mandated Integrity Programs</u> or designee shall be responsible for:

- Issuing Project Scope Documents and gaining approvals– See Attachment 3 Sample Project Scope Form (Not required when established by project development documentation).
- Initiating the Change Order Form (Attachment 1) for Category 1 and Category 2 Change Orders as necessary.
- Informing Process Manager, Project Manager or Regional Construction Manager of Change Orders.
- Approving non-complex design project for Category 1 and Category 2 Change Orders initiated by Engineering
- Approving all Category 1 and Category 2 Change Orders to complex design projects
- Assisting Operation & Construction in reviewing Change Orders and Completion of Change Order Form for complex projects

- Initiating, as required, and submitting Category 3 Change Orders for approval to Network Strategy and Regional Construction Directors
- Initiating revision of construction standards/drawings and Gas Work Methods as required
- Maintaining Project Change order Forms and Change Control Log in the Work Order/Project Folder and or project electronic data base

Network Strategy, Regional Construction Project Management and Complex Construction Directors shall be responsible for:

- Providing guidance and oversight, as needed, on pending Change Orders
- Approving Category 3 Change Orders

3. Personal & Process Safety

- MAH Assets – All changes to projects concerning assets within the Major Accident Hazard (MAH) portfolio (i.e., gas assets at pressures greater than or equal to 125psig, LNG assets, CNG assets) shall have a process safety risk-based review of the potential change in accordance with ***your company specific procedure***

5. Content

5.1. Change Classification Categories

a. All changes shall be classified using the categories below:

1) Category 1 –
Definition: Does not affect the design's form, fit or function (e.g., an elbow is moved 5 ft. to avoid an obstruction) and has negligible impact to the project's scope, cost or schedule.
   i. Usually identified by the construction crew and initiated by the Construction Supervisor or FCC.
   ii. Approved by a Design Engineer or, for non-complex design projects only, the Construction Supervisor / FCC or Project Manager.
   iii. When a change to an approved SOP is required, Gas Control must be notified.

2) Category 2 -
Definition: Changes that have minor impacts to the project scope and cost and do not impact the overall project schedule.
   i. These changes are within the spending limits of the project contingency and do not exceed 10% of the value of the project.
   ii. Change is usually identified by the construction crew and initiated by the Construction Supervisor or FCC (e.g., for a significant offset to avoid obstructions) or requested by the Design Engineer (e.g., to either to add or replace a component), thus affecting the design.
   iii. Approved by the Manager of Project Engineering & Design or, for non-complex design projects only, the Construction Supervisor /Design Engineer/ FCC or Project Manager when there are no deviations from drawings and/or Gas Work Methods.
   iv. When a change to an approved SOP is required, Gas Control must be notified.
   v. A Change Order Form or equivalent shall be completed for all Category 2 changes.

3) Category 3 –
   Definition: Changes that have a major impact to the project scope and cost and impacts the overall project schedule.
   i. Has costs exceeding 10% of the value of project.
   ii. It adds and/or replaces a major component and incurs significant man hours to the project. It affects the project schedule delivery date, and adds significant dollars to the project.
   iii. Usually initiated by the Process Manager (Construction/Field Ops) from the Originating Organization, Program Manager, Project Manager, Design Engineer, and/or Manager of Project Engineering & Design.
   iv. Requires approval by the Network Strategy Director or Regional Construction/Field Ops Director or Design Manager for Non-Complex projects
   iv. When a change to an approved SOP is required, Gas Control must be notified.
   v. A change Order Form or equivalent shall be completed for all Category 3 changes.

5.2. In Process Design Changes

a. A design change made during the design process before the final design is issued and before long lead material is ordered is an In-Process Design Change.
   1) Project scope and design changes may be requested by any party involved in the project for a variety of reasons. Such scope or design changes shall be evaluated by the Project Engineer and approved by either the Manager of Project Engineering & Design or a designated Project Engineering & Design Team Lead. Such approvals shall be obtained prior to finalizing the design and shall be reflected on the final scope document
   2) In Process Design Changes do not require completing a Change Control Form
   3) A Process Safety Risk based review of the potential change may be required in accordance with ***your company specific procedure***

5.3. Change Order Process

a. The person initiating the request has the responsibility of categorizing the change and identifying the time requirements, as well as the required approvals of the requested change in order to facilitate the project execution.

b. To avoid impacting the overall project schedule the Regional Manager of Project Engineering & Design, Process Manager, Project Manager or Regional Construction/Field Ops Manager shall be responsible for ensuring the required approvals are obtained.

c. The following inputs are recommended for preparation of project change requests.
   1) Sketches, maps, drawings, photographs, memos or other documentation specifying change
   2) Baseline plans of cost, scope, schedule, quality and risk management
   3) Description of the requested changes
   4) Project Status reports
   5) Work performance information
   6) Time reporting system reports
   7) Cost reporting system reports

d. Outputs/Deliverables for Change Order Approval
   1) A completed Project Change Order Form. See Attachment 1, Sample Project Change Order Form.
   2) Revised estimate

3) Schedule variance analysis
4) Preventive and Corrective Actions (If required)
5) Forecast at completion (revised Projected Year End Calculations (PYE)

5.4. Preparation and Approval of Change Orders

a. Category 1 Change Order – Verbal Approval
   1) Initiated By: Design Engineer or Construction Supervisor/ FCC.
   2) Approved By:
      i. Complex Construction: Project Engineering & Design
      ii. Non-Complex Construction: Design Engineer, Construction Supervisor/ FCC or Project Manager

b. Category 2 Change Order
   1) Initiated and Prepared By: Design Engineer or Construction Supervisor/CO Inspector/ FCC or Project Engineering & Design Manager, Process Manager, Project Manager or Regional Construction Manager
   2) Approved By:
      i. Complex Construction - the Manager of Project Engineering & Design.
      ii. Non-Complex Construction - (no deviations from drawings and/or Gas Work Methods) the Design Engineer /Construction Supervisor / FCC or Project Manager
      iii. Non-Complex Construction – (Deviations from drawings and/or Gas Work Methods) Contact Gas Work Methods/Materials and Standards for evaluation and approval.

c. Category 3 Change Order

   Category 3 Out of Process Changes require that approvals be obtained prior to performing the work in the field

   1) Initiated and Prepared By: Project Engineering & Design, Project Management or Construction Reviewed By: Project Manager, or Regional Construction/Field Ops Manager/Design Manager/Design Engineer
   2) Approved By: Network Strategy and Regional Construction/Field Ops Directors or the Design Manager for Non-Complex projects.

5.5. Change Control Log

a. A Change Log shall be kept by the Program Manager, Project Manager, or Regional Construction Manager/ Design Manager for all qualifying projects. See Attachment 2, Sample Change Control Log

5.6. Records Management

a. A copy of the Change Order Form shall be filed with the project documents and/or Work Order Package and a copy sent to:
   1) Complex projects: PE&D
   2) Non-Complex Projects: Regional Construction/Field Ops Manager/Design Manager or Regional Construction Manager
   3) A copy must also be sent to the Construction Control Project Manager

b. A copy of the Change Control Log shall be filed with the Project documents and /or work Order package

Change Control # Date:		Region:
LDC Company☐ Contractor ☐		Project Information
Name:		Project Name/Address:
Yard/Barn/Location:		Originating Org: ☐ City/State Construction
Change Order Category		Purchase Order #:
☐ 1. Cat1 (Low Impact) ☐ 2. Cat 2 (Minor) (< 10% of estimate)		Project Manager:
☐ 3. Category 3 (Major) (> 10% of prior estimate)		FCC/Supervisor

Project Accounting						
Region	Activity or ACE Code	Work Order No.	Expense Type	Originating Department	Original Estimate	Change Amount or %

Description of Change:
If Temporary change, latest date before temporary change must be removed:

Reason for Change:	**☐Field Conditions**	**☐Scope Change**	**☐Design Change**	**☐Other**
Explanation:				

Change Notification			
Name	**Title/Position**	**Method**	**Date**
	Originating Organization	☐Verbal ☐ Writing	/ /
	Gas Construction/Maintenance	☐Verbal ☐Writing	/ /
	Resource Planning	☐Verbal ☐Writing	/ /
	Project Management/Engineer	☐Verbal ☐ Writing	/ /
	Other:	☐Verbal ☐ Writing	/ /

Pricing Terms				
Fixed		**Variable**		**Amount(s)**
☐ Lump Sum	☐Unitized Pricing	☐ T&E	☐ Cost Plus:_____%	**$**
		☐ Not to Exceed		**$**
☐ All-inclusive, including all required temporary & final restoration.				**$**
☐ Exclusions:				**TOTAL**
				$

Approval(s)					
Title:			**Title:**		
Print		Date	**Print**		Date
Signature	X_____________________________		**Signature**	X___________________________________	

Project Change Control Log

Region/Company:

Project/Work Order #:

						Approval Information		
Date Requested:	**Requested By:**	**Department:**	**Reason for Change:**	**$$ Amount of Change:**	**Recommendation:**	**Approver:**	**Date**	**Yes/No**
				0.00				

Appendix 10

EDR Guideline Safety Management System Conformance Independent Assessment

The NGA Gas System Engineering Design Review Guideline
A Reflection of an API RP 1173 Pipeline Safety Management System

Mark Weesner P.E., Stacey Gerard and Mark Hereth
The Blacksmith Group

Introduction

This document demonstrates how the draft Northeast Gas Association (NGA) Gas System Engineering Design Review Guideline (EDR) embodies the elements of API RP 1173 providing an equivalent level of safety to the use of a professional engineer. The EDR provides a process to ensure conformance relevant to local, state and federal construction codes, permit requirements and compliance with pipeline safety regulations. It has been written to allow individual member companies the flexibility to incorporate specific organization policies, procedures, construction practices, drawings strengthened by specific controls. The EDR has been written to conform to the requirements of API RP 1173 Pipeline Safety Management System which serves as a foundation for systematizing and strengthening the EDR process for members companies.

Gas System Engineering Design Review Summary

The EDR guidance document is intended to provide NGA Pipeline member organizations a process framework for developing, enhancing and implementing an organization specific gas system engineering design review protocols. The goal of using a gas system design review process is to ensure that gas transmission and distribution systems are designed and constructed so they can be operated in a safe and reliable manner, increasing the likelihood of reducing incidents to our goal of zero.

The EDR essentially follows a “defense in depth” strategy. By assuring more than adequate levels of protection in the review process, member organizations adopting the practice bring in sufficient, broad technical perspectives to identify potential risks or weak links. The EDR ensures that members integrate this risk-based thinking from design through construction and inspection of construction. The defense in depth is also exemplified through “levels of protection” that are built through the selection of subject matter experts and reviewers who can bring a very robust set of “multi-disciplinary “skills, knowledge and experience to the process. The selection of reviewers includes all affected by the design, construction, start-up, and operation of the system and those who have an added contribution to make through their technical knowledge and experience. Further, this process raises the visibility of the accountability of all involved and makes accountability a continual process. Accountability is intended to be transparent which is an important factor in growing the safety culture in member organizations employing the review process.

Gas System Engineering Design Review Summary (Cont'd)

Engineering design reviews for natural gas system assets and operations can range from:

- *Simple* changes based on field operations enhancements to existing organization specific standard approved designs, to
- *Complex, non-standard* designs that include many linked stakeholders and subject matter experts from the member organization.

Regardless of design complexity, organization size or scale of assets being managed, each organization should have in place a design review process that is conducted by competent personnel that ensures an appropriate review of essential elements of the design with a focus on pipeline/process safety, constructability and operability. Competency is well defined in the process through the detail specified for each role and set of responsibilities.

The design review process requires consideration and evaluation of risk in the process, including but not limited to, specified materials, construction techniques, and operational requirements for management of pressure (isolation and depressurization of segments and systems as well as reintroduction of pressure). The process establishes the use of "Safety Gate Reviews" associated with project design/review/implementation resulting in an end-to-end Safety in Design process.

The Gas System Engineering Design Review Process includes the following content:

- Purpose
- Leadership and Stakeholder Engagement
- Essential Elements of Gas Engineering Design Review
- Training, Education and Experience of Competent Person(s)
- Standard Engineering Designs, Application of Standard Designs, Construction Drawings and Procedure Reviews
- Complex, Non-Standard Engineering Design, Development of Site/Project Specific Non-Standard Designs, Construction Drawings and Procedure Reviews
- Management of Change Policy (MOC)/Operational Controls
- Safety Assurance
- Continuous Improvement Practices Related to Engineering Design/Management Review
- Documentation and Recordkeeping.

The requirements provide a framework of *checks and balances* to ensure facility design, construction, start-up, and operation are performed consistently and more importantly provide pipeline operating organizations with the fundamental guidance to ensure sustainable positive safety outcomes.

Gas System Engineering Design Review Summary (Cont'd)

Within the essential elements, a set of principles are defined to guide operators' execution of the Design Review Process. Application of these principles will bring a level of quality and completeness to the review process which may not otherwise have been in place in operators' practice. Clearly, the guideline is intended to raise the bar, especially through the focus on objectivity, multidisciplinary input, and visible and continuous accountability. The concept of deepening the levels of protection goes directly to avoiding the potential for weaknesses aligning to cause a failure as depicted in the infamous "Swiss Cheese Model".

There is a spirit of inclusiveness underlying the principles outlined which would lead to employees being open to volunteer for participation in the design review processes. Further, the documentation of the reviews for complex, non-standard projects, leading to the signoff of a chief technical executive, expert, or approved designated alternate sends the message that the organization wants to be proud of having a comprehensive process. Transparency in accountability leads to open communication, an essential element of a good safety culture. Improved safety culture leads to improved safety performance, the goal of improved Design Review.

Contribution of API RP 1173 Element Requirements to the EDR Document

The NGA Gas System design review process draws in many of the element requirements of the API RP 1173 Recommended Practice. Inclusion of the API RP 1173 elements in the design review process results in required actions by individuals and the organization consistent with key Leadership, Stakeholder Engagement, Risk Management, Operational Control, Lessons Learned, Safety Assurance, Management Review/ Continuous Improvement, Competency/Training, and Documentation principles, all of which serve to strengthen and add cohesiveness to the design review process.

The structure of this Design Review essentially follows the principles of Plan, Do, Check, Act, which underpins the API RP 1173. With the focus of the Gas System EDR being on inclusiveness of layers of protection, it opens the process to employee involvement and contribution of personal responsibility on their part. This concept is central to API RP 1173. The following summary ties many of the Gas System EDR design review requirements to key API RP 1173 element requirements.

Leadership

- The Gas System design review process establishes the expectation that the organization will conform to specific standards, processes, and procedures.
- Leadership by undertaking this enhancement to design review is making a clear commitment to improved safety and system reliability.

Leadership (Cont'd)

- The process sets the expectation that all personnel and contractors who participate in the design-construction review process do so commensurate with scope and complexity of design/design change under review and consistent with their training, knowledge and competency.
- Roles, responsibilities, authority and accountability for each position are clearly defined for execution.
- Member company Leadership, adopting the design review process, establishes the Delegation of Authority necessary for Engineering Approval and visible sign off by a senior technical executive on the final company specific design review process/procedure.

Stakeholder Engagement

- The design review process requires utilization of personnel from all parts of the organization, as appropriate, including field operations, engineering (including Professional Engineers and/or Technically equivalent), consultants and contractors.
- Leadership communication welcomes employee involvement and taking ownership of the assets as their personal responsibility.
- Emphasis on transparency leads to an open environment where employees would feel safe about offering their safety concerns.

Risk Management

- The review process includes a requirement for assessing design/operational risk, where appropriate, including identification of potential abnormal operating conditions (AOC's) resulting from design implementation.
- The process includes consideration, based on design/operational risk, of a Pre-Startup Safety Review process (PSSR) and a System Operating Procedure process (SOP) where required.
- The process requires identification of potential risks associated with the change and any required approvals prior to introduction of such changes.

Operational Controls

- The design review process requires organizations using the design review process to maintain and utilize written construction, maintenance and operations procedures.
- The process requires review of material specifications, system/equipment design, construction processes and field construction inspection consistent with design requirements.
- The process contains requirements for a robust MOC process consistent with the requirements of API RP 1173.
- Emphasis on accessibility increases the likelihood of consistent use of approved procedures and better quality control.

Incident Investigation, Evaluation, and Lessons Learned

- The design review process requires a continuous improvement process related to engineering design to incorporate the results of incident investigations, evaluations and lessons learned.
- Consistent monitoring through management review of lessons learned and applied provides greater assurance learning is applied system wide from specific findings.

Safety Assurance

- The design review process requires the use of pre-defined "Design Review Gates", creating an objective and transparent review process that, in many cases, is independent of the original design review process based on design complexity.
- The process requires, when specified, use of individual(s) not directly involved in the process to ensure that conflicts of interests do not arise.
- Commitment to an audit of this process as a priority provides an added level of safety assurance.

Management Review and Continuous Improvement

- The design review process specifies use of a continuous improvement process requiring the use of periodic reviews of gas system designs to ensure that changes to specific designs, feedback from lessons learned, and evaluation of risk are feedback to the training organization.
- Periodic reviews of metrics are required such as stakeholder feedback; equipment reliability, performance and availability; gas system operational performance; incident investigations, near-miss evaluations and lessons learned; and results of risk management reviews, internal and external audits.

Competency, Awareness and Training

- The design review process requires that design reviews are carried out by suitably trained, competent individuals who are experienced in gas system design and operations possessing the ability to comment constructively from the standpoints of constructability, operations, pressure control and work site safety.
- The process establishes training, education and experience requirements for personnel deemed as competent to carry out the design-construction review process.
- Specific competency requirements are very detailed for each role in the process along with sources, options, and variations to provide adequate knowledge required.

Documentation and Record Keeping

- The design review process contains requirements for identification, distribution, and control of documents to memorialize the review process.

- The process requires identification of the approval authority for document approval/sign-off, re-approval and assurance that documents and records supporting the design review process are readily identifiable and available for future use.
- Requirements for accessibility and transparency provide an added level of assurance that employees can reliability find and use what is needed.

Conclusion

The guideline makes a clear case for how a robust design review *process* provides better protections through layers supported by a structured process rather than relying on a single credentialed individual (PE). Through an emphasis on visible and transparent accountability, employees will be motivated to add their perspective, adding a sense of more well-rounded review. Operators undertaking this design practice will realize how the bar is raised through greater completeness and comprehensiveness of reviews and be able to execute reviews with greater certainty as to the goal of zero incidents. Finally, the principles espoused in this guideline reinforce the sense of openness in communication and information flow needed to nurture a healthy safety culture important to inform better decision making.

NGA
NORTHEAST GAS ASSOCIATION

SGA

Management of Change Applied to Local Distribution Company Operations

PSMS Technical Guideline

Prepared by: The Blacksmith Group

05/08/2023

Foreword

This Technical Guideline draws upon experience in the pipeline and other industries in highlighting the importance and the value of Management of Change (MOC) throughout the life cycle of a distribution system, including design, operations, maintenance, integrity management, emergency response, and abandonment, including temporary and emergency changes. While the emphasis will be on distribution systems, the principles, processes, and considerations provided herein can be applied to transmission as well.

This Guideline is intended to highlight considerations to support members in managing change in their respective organizations. The Guideline also provides background on Management of Change fundamentals, including promulgated legislative requirements, provisions outlined in standards such as API RP 1173, Pipeline Safety Management Systems, and learning from the application of Management of Change in other industries, including chemical and petrochemical, petroleum refining, commercial aviation, and food processing among others.

The Northeast Gas Association (NGA) is a regional trade association serving more than 35 companies that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas, including natural gas pipeline safety within the Northeast region of the U.S. The Northeast Gas Association represents gas distribution companies, transmission companies, liquefied and compressed natural gas suppliers, and associate member companies. NGA member companies provide natural gas service to over 14 million customers in 9 states (CT, MA, ME, NH, NJ, NY, PA, RI, and VT). NGA publications are developed by membership committees and are intended to facilitate sharing of broad, proven, sound engineering and operating practices. Publications may be used by any member desiring to do so. Every effort has been made by the NGA to assure the accuracy and reliability of the data contained in them; however, the NGA makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

Members of the Southern Gas Association (SGA) joined NGA members in developing this technical guideline. SGA is a regional trade association that focuses on education and training, technology research and development, operations, planning, and increasing public awareness of natural gas, including natural gas pipeline safety throughout the U.S. SGA represents gas distribution companies, transmission companies, liquefied and compressed natural gas suppliers and associate member companies.

Acknowledgment

The NGA PSMS Implementation Collaborative is focused on strategic and practical approaches to making *PSMS real* in day-to-day operations. The Collaborative incorporates the use of focused technical work groups to develop consensus-based PSMS implementation tools, including Technical Guidelines, which are intended to provide participating organizations with an opportunity to share and discuss applicability of leading practices. The *Management of Change (MOC) for LDC Operations Technical Guideline* was developed by the PSMS Implementation Collaborative and included participation by the following organizations:

- Central Hudson Gas & Electric
- Consolidated Edison Company of New York
- Duke Energy
- Eversource
- Exelon
- Holyoke Gas & Electric
- Liberty Utilities
- National Grid
- Network Infrastructure
- Southern Company
- Unitil
- VGS
- Westfield Gas + Electric

NGA and participating sponsors would like to thank our consultant, The Blacksmith Group, for their support and insights in facilitating the development of this Guideline. In addition, NGA would like to thank State Regulatory Authorities for their active participation in the PSMS implementation process and for their insights in developing this Guideline as a tool to achieve our shared goal of enhancing pipeline safety culture. These organizations include the Connecticut Public Utilities Regulatory Authority (PURA), the Massachusetts Department of Public Utilities and the New York State Department of Public Service.

Management of Change

Applied to Local Distribution Company Operations

1.0 Introduction

The Northeast Gas Association (NGA) initiated a collaboration among 13 members in the Spring of 2019 to assist them in assessing their conformance with requirements of the American Petroleum Institute (API) Recommended Practice (RP) 1173, Pipeline Safety Management Systems (PSMS) led by the Blacksmith Group ("Blacksmith"). NGA established a PSMS Implementation Committee to define the scope of initiatives, provide oversight on work conducted and share results and learning with the NGA Board, and more broadly NGA members, the industry, state officials, and the public. Phase I of the work initially focused in supporting members who were beginning the PSMS journey in the development of gap analyses, referred to as "build-on" analyses, to identify existing processes and programs to "build-on" in defining a path, a "road map," unique to each member to better conform with the requirements of API RP 1173. For those members that had started the PSMS journey, work in Phase I was directed at assessing the state of implementation of the requirements of API RP 1173 and providing perspectives and opportunities to enable their conformance. Phase 1 work also entailed development of "tools" to operationalize the thinking of a PSMS and use of Plan, Do, Check and Act into everyday work through Tactical Guides and Technical Guidelines.

In conducting the "build-on" analyses for members in Phase I, Blacksmith recognized the challenges that members were facing in developing Management of Change (MOC) processes and proceduralizing the processes to work for the broad range of changes managed within a local distribution company (LDC). The purpose of this technical guideline is to support operators in developing and improving MOC within their respective organizations. As with development all NGA technical guidelines, the purpose is to provide a mutual learning forum to share scalable, leading practice consideration. This Guideline is intended to assist operators with initial implementation and continuous improvement of the application of MOC. While the emphasis will be on distribution systems, the principles, processes, and considerations provided herein can be applied to transmission as well.

2.0 Background

The Northeast Gas Association brought together a work group to develop this guidance for members to consider

in developing and evaluating their MOC processes/ procedures specifically focused on LDC operations[1]. The objective of the work group was to develop guidance to assist members in meeting the MOC requirements of federal pipeline regulations and PSMS guidelines as provided in API RP 1173. This guideline has drawn from the experiences and learnings from:

- Operators
- Contractors

[1] MOC is required under current U.S. Department of Transportation, Pipelines and Hazardous Materials Safety Administration regulations for gas transmission integrity management, control room operations and for remaining portions of gas transmission on February 24, 2024.

- Regulators
- Other industries

The work group defined a series of principles at the outset of developing guidance. The principles are:

- Operationalize – integration of MOC throughout an organization
- Inclusion and engagement of the organization, operations, engineering, construction, and projects in evaluating changes,
- Buy-in throughout the organization
- Keep the process simple
- Scalable – to address size of organization, number of MOCs processed and may include risk assessment, high, medium, and low risk
- Importance of communication – sheer number of employees in operations and methods of communication – written materials, ensuring comprehension, volume, and pace of change
- Role of culture - What is a change and what do we do, knowing that? Awareness of MOC and responsibility/ to initiate
- Remove pain points
- The importance of explaining the "why"; Questions to keep in mind - Who, What, When, Where and Why

The MOC process should be fit for purpose and scalable commensurate with the complexity of change. MOC of procedures can be defined within a document for managing procedures or managed through an organization-wide MOC process.

3.0 Purpose

This NGA Technical Guideline provides considerations and guidance for developing and improving MOC processes to evaluate technical, physical, procedural, and organizational change activities for potential impacts and unintended consequences prior to implementation. Management of Change may supplement existing policies or procedures, and includes temporary, emergency, and permanent changes in operations, maintenance, products, treatments and additives, procedures, facilities, and personnel. Any conflicting information that may be found between this system and any other policy/procedure should be brought to the attention of the respective document owner/author for clarification.

4.0 Scope and Objectives

4.1 Scope

The scope of these MOC guidelines is to identify proposed changes; assess and evaluate impacts, and systematically manage any changes to pipeline facilities and associated infrastructure. This process is intended to address unmanaged changes and may supplement existing MOC processes in the organization.

4.2 Objectives

An effective MOC process has the following objectives:

- Improve the management of the organization’s facilities by proactively managing physical, procedural, technical, organizational, or regulatory changes impacting the pipeline system and associated assets.
- Ensure that changes in the pipeline system design, construction, operation, maintenance, abandonment, or in the environment, in which pipelines operate, are evaluated for the impact of unintended consequences.
- Identify where unintended consequences warrant consideration of risk in a more formalized manner.
- Establish and maintain effective methods for documenting changes to help maintain the integrity of the pipeline system.
- Identify and address training and qualification needs of an organization’s personnel and contractors as a result of changes.
- Establish and maintain effective methods of communicating changes to appropriate people and organizations both inside and outside the organization.
- Incorporate change information into future pipeline assessments for integrity management purposes.
- Incorporate change information from the integrity management program into appropriate systems.
- Incorporate key components and requirements for updating procedures and standards.
- Incorporate procedural change information for updating procedures and standards
- The process should be flexible enough to accommodate major and minor changes while maintaining continuity of operation.
- Assure that all required pre-implementation actions, including training, qualification, and safety reviews, are completed, and documented prior to the effective date of the change and that all actions required by the change are tracked to completion.

5.0 Related References and Key Interfaces

5.1. Key Links to other Systems and References

When developing a Management of Change process, the process owner determines if there are any interdependencies to other processes, programs, and procedures and if so, insure consistency and completeness. These links are documented in the MOC Plan.

Additional codes, standards, and regulations to consider include the following:

- API RP 1173
- Northeast Gas Association Engineering Design Review Technical Guideline
- American Gas Association - Natural Gas Utility Guideline for Developing a Management of Change (MOC) Plan for Engineering Design, 2021.
- Environmental Management Systems
- ASME B31.8S – Managing System Integrity of Gas Pipelines
- ISO 31000 – Risk Management (check for MOC and PAS 55)
- Code of Federal Regulations Title 49- Transportation
  - Control Room Management – 49 CFR 192.631(f)
  - Transmission Integrity Management – 49 CFR 192.911(k)
  - OSHA – 29 CFR 1910.119
- Center for Chemical Process Safety (AIChE))

5.2 Key Interfaces with Other Organizations

The Management of Change process identifies applicable stakeholder or SME interfaces within the organization. Some examples are:

- Pipeline Operations
- Engineering
- Project Engineering and Construction
- Materials management and purchasing
- Commercial
- Finance
- System Planning
- Customer Meters Services
- Pressure Regulation, Control and Odorization
- Distribution Integrity Management
- Transmission Integrity Management
- Gas Control
- Personal Safety
- Environmental, Health and Safety
- Training and Qualifications
- Legal/ Law, and
- Government and Public Affairs

6.0 MOC Considerations

API RP 1173 includes Management of Change as a sub-element under Operational Controls and includes the following sub-elements to consider in developing a new MOC process or evaluating and improving an existing process. These include:

a. reason for change,
b. authority for approving changes,
c. analysis of implications,
d. acquisition of required work permits,
e. documentation of change process,
f. communication of change to affected parts of the organization,
g. time limitations, and
h. qualification and training of personnel affected by the change (including contractors).

The elements are described in detail in the following subsections.

6.1. Reason for Change - Requesting Change

An MOC clearly identifies the proposed change(s) in order to ensure all aspects of the change are addressed properly. Each process has a formal method for requesting change.

Changes that typically warrant an MOC include new or modification of equipment, procedures, specifications, documents, regulations, processing conditions, personnel or other activity that will have an impact on the pipeline system or integrity program. Examples of change include, but are not limited to the following type of events:

- New operating, maintenance, inspection, or mitigation procedures
- Physical changes (additions, deletion or improvements) to the existing pipeline system
- Deviations beyond pre-approved operating range such as increase/decrease in operating pressure
- Changes in engineering standards or specifications
- Changes in reference codes and standards
- Software changes such as work management, control or PLC changes
- Personnel changes
- Changes in land use that impact the classification of system or require reassessment of risk analysis
- Acquisition of new assets
- Mergers
- Changes in the Pipeline Integrity program[2]

Typical examples of change are shown in Appendix A. Considerations in Determining if MOC Applies are found in Appendix B.

Management of Change **is not** intended to address low-impact activities such as "Replacement-in-Kind" or changes within pre-approved ranges or standards. However, the Process owner or facility operator may decide that the Management of Change process is warranted for certain low-impact activities. Appendix C has

[2] Required notification Office of Pipeline Safety for changes are significant.

examples of activities considered to have a low impact (Replacement in Kind) on pipeline integrity versus activities requiring Management of Change.

This process formally documents the change request information that is submitted for approval. Each process owner documents, at a minimum, the following information when a change request is made:

- Reason for Change
- Date
- Type of change (i.e., Physical, Procedural, Organizational, or Technical)
- Change description
- Change objectives
- Expected impacts of change
- Supporting documentation for change
- Effective change date
- Temporary or permanent

Upon completion of the change request document, the change initiator submits the request to the person/group responsible for the impact analysis.

6.2 Authority for Approving Changes

Once an MOC is initiated, and upon completion of an analysis of impacts (see Section 6.3), it is approved/ denied using a defined authorization process. An MOC process identifies personnel/positions that have approval authority and the type of change the person/position can approve. The individuals having *approval authority* are readily accessible and arrangements be made to cover non-accessible situations such as vacation.

A preliminary screening with all applicable supporting information is conducted determine whether to approve the MOC to proceed. If the change request is not approved, the approver notifies the requestor and documents reasons for not pursuing.

Approval or rejection of the change request is documented by obtaining the required signatures and date from the business unit's designated approving authority. The approving authority may choose one of the following outcomes regarding the proposed change activity:

- Approve Change as Requested
- Approve the change subject to specified conditions
- Request more information related to change prior to approval
- Reject the Change Request

Change requesters should be separate from the change approvers to avoid conflicts or the appearance of a conflict of interest. If the Change Request is rejected, the package is returned to the Change originator for closure or to resolve any issues for re-submittal. The approval/denial is part of record retention.

6.3 Analysis of Implications - Impact Analysis

Once an MOC is initiated[3], the proposed changes are evaluated for potential risks and the integrity of the pipeline system will not be compromised resulting from the change. Reviewers are identified for each component of change.

The review team considers appropriate physical, procedural, and organizational impacts resulting from the proposed change. The health and safety of employees, customers and communities, and the environment are considered while performing the analysis. The analysis includes the following topics for discussion:

- Identify the reasons for change and the objectives for the change. Determine if the same objectives can be met without a change to the pipeline system, process, or organization.
- Identify all affected internal and external parties. Determine how the parties are impacted.
- Identify parties involved in implementing the change[4]
- Determine the need for evaluation of risk (Refer to Appendix D).
- Determine if changes will have any immediate or long-term impacts to the integrity of the pipeline system.
- Consider how significant an impact the change will have on those using or operating the system. Determine if new procedures or training will be required for employees, contractors, or outside communities. If the change is an organizational change, training requirements and proper transfer of knowledge between incoming and outgoing personnel should be considered.
- Determine the communication content and logistics for adequately notifying the affected parties. Identify both internal and external communications. Consider the need to contact any outside agencies and/or communities.
- Take into consideration, which documents will be amended or created by this change, including permits, design drawings, Operating/Maintenance procedures, and organization charts.
- If the change is temporary, a defined duration is identified as to when the system will be returned to its original state. If the established duration of the temporary change cannot be met, a process is in place to reevaluate the change and reapprove, as appropriate.

[3] Some organizations require authorization to proceed.

[4] Changes in personnel resulting from extended workdays are addressed in a job hazard/ job safety analysis/ pre-job brief. Likewise, shift changes in a control room are managed through Control Room Management MOC process.

A summary of the *change impact analysis* combined with the original change request will be documented and submitted for the approval process. Key findings, along with supporting documentation and recommendations, should be identified to ensure the approving party is informed of the impacts.

6.4 Acquisition of Required Work Permits and Work Planning

The MOC process considers whether the change requires a permit or change to an existing permit. Permits may be from external entities such as federal, state, and municipal entities or internal permits for work activities. Considerations include:

- A clear and concise work plan (implementation plan) is developed in accordance with organization-specific policies using applicable standards and procedures. Deviations from approved procedures may trigger the Management of Change process. A copy of the final work scope is part of record retention.

- All necessary internal and external permits, rights-of-ways, and any other necessary approvals are obtained to complete the Management of Change process. Modify to address permits required to implement – not every permit requires completion during the MOC process, e.g., permits required to conduct work following approval of an MOC. Permits for new or modified assets which is approved prior to the effective date of the change should be clearly identified in the MOC process and differentiated from permits that may be completed following the approval of the MOC or start-up of the assets. All applicable permits and/or approvals are reviewed and forwarded to appropriate functions within an organization for accurate processing and record retention.

- The implementation plan includes the methods to be used for communicating change to all impacted organizations. Additional Management of Change communication requirements are included in Section 6.6 (Communication)

- If training and additional Operator Qualification (OQ) needs have been identified in the impact analysis, the work scope includes or refers to specific training and OQ plans for impacted individuals, organizations, or others. Additional training and OQ considerations are included in Section 6.8 (Competency, Training & Qualifications).

- The work scope is executed as designed and/or planned. Deviations from design and/or work plan should be documented and communicated to the person/group that is responsible for impact analysis to ensure deviations will not have any further impact on pipeline integrity.

All changes from design and plan for the change process outside of established guidelines require that this process be stopped and started over. ***Change within change is not permitted outside of the established guidelines.***

6.5 Documentation of Change

Each process owner identifies documentation that is affected by the change. Examples to consider are:

- Procedures/Standards/Guidance manuals, which provide details on how activities are to be performed to complete specific tasks.
- Records, Forms, Logs, Reports, Checklists, or any other tools used to demonstrate conformance with procedures.
- Project Files, which include as-built design/construction drawings, design data sheets, specifications, permits, contracts, and any other pertinent project files.
- Geographic Information Systems or other system databases

Details on management of change documentation are found in Appendix E. An example of a management change procedure is shown in Appendix F.

6.6 Communication of Change

Communications related to the MOC are fit-for-purpose and appropriate for the identified audience and may vary, depending on communication needs. Methods include, but are not limited to, interoffice documents, training sessions, bulletins and publications, contractor meetings, e-mail, websites, Public Relations, workday stand-downs, etc.

It is important to point out what action, if any, is expected from the audience receiving the communication. The person receiving the information should be able to answer the following questions:

- What is changing?
- Why am I being informed?
- How will I be impacted by this change?
- Do I have information relevant to the evaluation of the change, even though it may not directly impact me or my area?
- Am I expected to take any action based on this communication?

A point of contact should be identified in the event the audience needs additional clarification or information.

6.7 Time Limitations

Some changes require the establishment of time limitations for a proposed change. Examples include temporary changes, such as the isolation of a system or segment of a system. Emergency changes may also have defined authorization period limits. It is important that the time limits be evaluated in the impact analysis and subsequent steps. See section 8.0 for additional information.

6.8 Competency, Operator Qualification, and Training

The MOC evaluation process should include subject matter experts (SMEs) from an organization's Training and Operator Qualification area. Some changes may result in redefining an OQ Task. The Management of Change process associated with the OQ Program MUST be adhered to, and the resulting change implementation schedule may be impacted by necessary OQ Plan changes.

The planning/implementation group/person reviews the impact analysis for training and OQ needs and compares it to existing policies, procedures, and OQ requirements in coordination with the Training and Qualification areas to determine if additional training and/or OQ Plan changes are required. Training and OQ needs are communicated to the appropriate group(s) responsible for developing and performing training and OQ for the specific process owner. In addition, outside parties such as contractors and emergency response agencies may have to be trained, depending on the change's impact.

6.9 Other Considerations - Administration, Tracking, and Closure

Depending on the size of the organization and the number of changes, administrative support can be important to the success of the MOC process. Experience has shown that MOC administrative functions can be carried out by non-technical personnel to support the process steps defined above and elevate challenges to management for resolution and closure. Administrative support may not typically require full-time resources, but it requires dedicated attention at the right intervals to ensure the process is moving to completion. When the number of changes within an organization is significant, administration of the changes can also be aided by the use of a tool or application.

In evaluating risk, there may be mitigation measures undertaken to minimize unintended consequences. Mitigation actions are tracked and completed.

6.10 Post-Change Assessment

Post-change assessment for completed MOCs is considered part of a continuous improvement process. This step is performed to measure the effectiveness and sustainability of the change activity.

Lessons learned from the change activity should be captured and communicated. The feedback can be used for continuous improvement in the areas of facility design, operation, and training.

7.0 Regulatory Changes

The MOC process described above can be applied to address changes in regulations, including promulgation of new regulations. Organizations may have an established group dedicated to tracking regulatory activity and associated changes and reviewing them for consideration and incorporation into their processes and procedures. The text that follows can be used to evaluate an existing process and identify opportunities to improve them using the rigor of a PSMS MOC process.

Applying the first step, “Reason for Change”, provides an opportunity to document “why” the changes in regulation occurred in the procedures and supporting roll-out and training materials. Helping employees and contractors understand the background and basis for the regulatory change helps them see the value in adopting change and ensures buy-in and conformance. For example, is the change a result of a National Transportation Safety Board Recommendation, such as the one related to having records to support an established MAOP? Or is it the result of a new requirement in one of the states in which your organization operates?

The second step in an MOC process, authority for approving changes, described above, can also be applied to regulatory changes. The purpose in this application is to ensure that authority for evaluating and approving changes to processes and procedures is established in an organization’s governing documents. Similarly, for an existing process, “analysis of implications” can be applied to regulatory changes. Analysis of implications can entail consideration of the impact of changes, including changes needed to processes and procedures, and should include impacts on materials, tools, and equipment. Incremental changes to regulatory requirements resulting in capital and operating incremental costs may be recoverable through the jurisdictional rate-making process. It is important that your evaluation process includes a mechanism to capture and document all associated incremental costs.

While the step, acquisition of permits, generally would not apply with respect to regulatory changes, there is value in considering whether there will be permit requirements resulting from the regulatory change. Documentation of changes will be made in process documentation, procedures, and specifications, as well as supporting MOC process documentation. Communication of changes for regulatory changes is typically part of a defined process for roll-out and training regarding changes.

Time limitations apply for regulatory changes, based on the timing of effective dates, particularly for regulatory changes that have multiple phases in effective dates or that have interactions with other regulatory changes or ongoing activities.

Finally, the evaluation of training and required changes/ updated OQ of personnel is an essential step in addressing regulatory changes.

8.0 Emergency and Temporary Changes

8.1 Emergency Changes

Emergency changes are requests that must be completed immediately and cannot wait until the completion of a formal Management of Change process. All emergency changes require approval from a designated senior manager. When implementing an emergency change, consideration should be given to use of appropriate mitigations, make safe actions, or layers of protection to help protect against unintended consequences until the change can be fully reviewed and approved. Emergency changes can have a shortened process, involving key personnel.

After the emergency has been managed, the Management of Change process is initiated and completed. All steps in the process are completed. This includes documentation as to what constituted the change to be an emergency.

Before an emergency change is commissioned, it is the responsibility of the approving authority to ensure the affected individuals [that identified the change] are informed and ensure their understanding of the change.

8.2 Temporary Changes

Temporary changes are defined as having an expected time limitation (e.g., temporary bypass). The maximum time limit is declared in the Management of Change process. Temporary changes *must still meet all Management of Change requirements,* except that they may be limited in activity and duration. Limited communication and post-change risk assessment may suffice if the temporary change will be returned to its original condition within a specified time frame. The extent of follow-up for each process step is determined during the impact analysis.

In addition to meeting all Management of Change process steps, a date will be given stating when the change is to be returned to its original state. If the temporary change date is extended, the change originator will need to determine the new date and resubmit the original request, as a revision, to the approving authority for approval and another impact analysis performed.

When the temporary change is returned to its original state or is made into a permanent change, communication is made to all impacted individuals.

NOTE: Temporary changes of limited scope and/or duration require careful evaluation and are considered in pre-job briefs and post-job assessments. While temporary, the risk of unintended consequences is increased as temporary changes may result in complacency since the change is not viewed as permanent. Temporary changes can result in catastrophic results such as system over-pressurization or unintended loss of pressure. Change Management Checklists are particularly useful as part of a pre-job brief when a temporary change is anticipated to ensure original design conditions are restored. All associated temporary change procedures, such as lock-out / tag-out, validation of change with gas control and/or an appropriate supervisor, and a “trust but verify” approach to validating return to original conditions prior to the temporary change is prudent.

9.0 Process Reviews and Audits

The Management of Change process should be periodically reviewed to ensure its completeness, and effectiveness and that personnel and process owners are in conformance with the provisions of the plan and

API RP 1173. API RP 1173 specifies a review and evaluation every three years. The review process should also include feedback and recommendations from individuals involved in completed MOCs using the system. The system review is conducted according to a schedule and plan established by the process owner.

10.0 Contribution of API RP 1173 Requirements to the NGA Management of Change Technical Guidance Document

API RP 1173 provides pipeline operators with safety management system requirements that provide a framework for managing risk, promoting a learning environment, continuous improvement, and developing a strong, positive culture of safety. The framework of elements in API RP 1173 enables an operator to define processes and address safety for a pipeline's entire life cycle. Management of Change is a key process for identifying and addressing risks connected to changes in technology, equipment, procedures, and organizational/ personnel.

The NGA Management of Change (MOC) Technical Guidance document draws upon several of the API RP 1173 element requirements and the Plan-Do-Check-Act Cycle (PDCA). The PDCA cycle is a model for continuous improvement and implementing changes, which require an understanding of the risks and possible unintended consequences associated with the change. API RP 1173 elements that support effective implementation and execution of the Management of Change process are: Leadership & Management Commitment, Stakeholder Engagement, Risk Management, Operational Controls, Incident Investigation, Evaluation & Lessons Learned, Safety Assurance, Competency, Awareness & Training, and Documentation & Record Keeping, all of which serve to strengthen the Management of Change process.

Leadership and Management

- Leadership fosters a culture of systematic consideration of risk, seeking to understand "what can go wrong?", including managed changes in procedures, equipment, technology, or organization.
- Leadership helps ensure that required changes are analyzed for risk and unintended consequences by allocating the appropriate resources (SMEs) for analyzing changes. Changes and "why" they are being made are communicated to the organization, and plans for the change roll-out are formalized for a smooth implementation.
- Employees gain a better understanding that safety is valued as they see leadership and management support a management of change process that ensures that managed changes are reviewed and approved prior to implementation.

Stakeholder Engagement

- Managers and employees see that their organizations are involved in evaluating and designing changes.
- Employees see that the reasons for change and plans for the change are shared with them and their organizations.

Risk Management

- The Management of Change process is a risk analysis and mitigation process for changes in technology, equipment, procedures, and organization/ personnel.
- The term “threat” is applied both specifically and broadly within a PSMS. A threat might refer to a specific pipeline integrity or operations risk. A threat can also refer to potential impacts of a change, such as the potential loss of knowledge and experience from retirements and attrition.

Operational Controls

- The Operational Controls section of API RP 1173 requires organizations to maintain a procedure for managing changes in technology, equipment, procedural, and organization/ personnel.
- The API RP 1173 requirements for management of change, including documenting the reason for changes, assigning the authority for approving changes, conducting an analysis of consequences of the changes, acquisition of required work permits, documentation of the changes, communication of changes to affected parts of the organization, and qualification/ training of personnel affected by the changes, all of which work in concert to minimize the risk of implementing the changes.

Incident Investigation and Lessons Learned

- Findings and lessons learned from incident investigations, near-misses, and external events are valuable sources of information to aid in the analysis of proposed changes, including consideration of unintended consequences.

Safety Assurance

- Audits and evaluations are used to determine how effective the management of change process is working and how consistently it is used across the organization.

Competency, Awareness, and Training

- Awareness and training are used to ensure that personnel impacted by changes have the requisite level of competence in terms of education, knowledge, and experience.

Documentation and Recordkeeping

- Documents developed and produced during the management of change process follow the organization’s procedure for the identification, distribution, and control of documents required by its pipeline safety management system.
- Results of the analysis associated with approved changes, including the rationale or reason for the changes, the change approval, and specific steps in the change roll-out, are included in the management of change documentation.

Appendices

Appendix A

Typical Examples of Change

Typical instances of change where an operator should consider Management of Change are listed below. The list is not all inclusive and serves as a guide in determining the applicability of the review process.

Assets Including Facilities:

- Construction of new or replaced mains, services, equipment, or facilities (e.g., pipelines, measurement and regulator stations, compressor stations, storage equipment and instrumentation and control equipment)
- Modifications and additions of existing facilities, including low pressure to high pressure uprates
- Replacement of equipment that is not replacement in kind
- Modifications of control or other systems which cause changes to pressure relief requirements, safety systems or alarms
- Bypass connections around equipment of facilities normally in service
- Changes in proximity of equipment, including thermal and vibration

Technical (Including Safety Systems):

- Increasing throughput or capacity rate
- Introduction of new or different products such as chemical injection
- Changes in gas quality
- Changes to critical testing and inspection equipment
- Changes outside of established parameters for pressure or temperature
- Changes in electrical, control, interlocks, or instrumentation outside of established parameters
- Changes in software that impact asset operation, safety limits, operating parameters, and calibration
- Changes to integrity management parameters (such as data collection requirements), or output (such as modification of DIMP to include impact to the environment)
- Changes in regulatory requirements, reference codes and standards or legal interpretations Resulting in new or revised technical guidance (e.g., repair or assessment criteria)

Procedural:

- Changes to or new operating, inspection or maintenance procedures or standards
- Operations outside the scope of current procedures or standards
- Changes in material or construction specifications
- Changes in regulatory requirements, reference codes and standards or legal interpretations
- Changes in quality control or quality assurance procedures

Organizational:

- Changes in organization of personnel that supervise or operate the facility
- New employee or transferred employee with a specific skill set where re-qualification is required
- Change caused by employee attrition – identify responsibilities to assigned/ transferred
- Changes in the management, acquisitions, mergers, and divestitures

Back to Document

Appendix B

Considerations in Determining if MOC Applies

If the answer to any of the questions below is "yes", then the change is applicable to the Management of Change Process. If all the answers are no, Management of Change is not required. If in doubt, proceed with the management of change process.

1. The established safe work practices or approve procedures do NOT address the potential change?
2. The replacement equipment does NOT meet the original specification or current configuration, functionality or capabilities (like for like)?
3. Does the work involve addition or deletion or equipment?
4. Is the addition or deletion temporary or being done on an emergency basis?
5. Will the logic, including set points, of operating, monitoring, control, or safety systems change (including SCADA) and software updates?
6. Will drawings/ schematics, P&ID's, physical capacity, secondary or emergency systems change?
7. As a result of this change, is it possible for operating parameters to deviate from currently established limits (e.g., change in valve type, regulator, mechanical equipment, etc.)?
8. Could the change adversely affect the environment, including increasing emissions?
9. Will the work require approval of changes to existing permits, plans, or programs?
    - Within the organization
    - Regulatory
10. Is the change to the testing, inspection, or maintenance programs?
11. Does the action result in a new or revised procedures or deviation from safe work practices?
12. Is the result of a change in legal, regulatory, or policy requirements?
13. Does the change involve organization or personnel qualification changes (e.g., personnel changes on projects or program leadership to ensure proper transfer of responsibilities)?

Back to Document

Appendix C
Low-Impact Activities

Replacement in Kind (IK) changes entail use of functionally similar/ equivalent equipment, materials, and tools.
Like for Like (LL) changes are low impact changes that use the same size, material, style, manufacturer, range, control, operation, procedures, etc. Examples of Like for Like include the following:

- **Valves –** Replacement of existing valves including block valves, regulator and relief valves, and flow control valves with valves of the same design capabilities. This includes pressure rating, material of construction, nominal size and joining type.
- **Pipe –** Replacement of pipe has a matching nominal size, within the tolerances of the manufacturing specifications. The manufacturer may differ.
- **Flanges and Other Components –** Replacement of flanges and other components such as fittings, have matching nominal size, within the tolerances of the manufacturing specification. The manufacturer may differ.
- **Electrical –** Replacement of electrical equipment including motors, fuses, breakers, and wiring where the replacement is of equal rating, gauge, current carrying capacity, voltage, horsepower, speed, and type.
- **Instrumentation and Control –** Replacement of instrumentation, controls, valve positioning, SCADA, alarms, sensors with items of similar ratings and operation limitations. Changes of set point within established ranges, and routine testing and maintenance of devices. Changes that impact human machine interfaces (e.g., displays, screen schematics).
- **Measurement Equipment –** Replacement of equipment which has the same pressure rating, materials of construction, size, flow rating and operation.
- **Operations and Maintenance** – Variations in operating parameters which are within the limits as described in the standard or operating procedure such as flow, pressure, and temperature. Changes in maintenance practices which are within the limits as described in the operations and maintenance procedures.
- **Organization –** Reassignment of qualified personnel, regular crew changes and other changes within prescribed parameters of the administration policies.
- **Storage** – replacement of storage vessels which has the same pressure rating, capacity, and materials of construction.

Back to Document

Appendix D

Sample Risk Matrix

Depending on the complexity of changes being evaluated, one can consider use the Risk / Consequence Evaluation Matrix :

Likelihood/ Consequence	**Probable (3)**	**Possible (2)**	**Extremely Unlikely (1)**
High (3)	9	6	3
Medium (2)	6	4	2
Low (1)	3	2	1

DEFINITIONS

Risk:

- **Probable:** Could occur once within 1-5 years
- **Possible:** Could occur once within 5-10 years
- **Extremely Unlikely:** Could occur once within 10-100 years

CONSEQUENCES:

- **High:**
    - Significant impact on human health or the environment
    - Significant consequences to meeting customer deliveries
    - Significant legal and/or financial exposure
    - Long term damage to reputation and image

- **Medium:**
    - May impact human health or the environment
    - Will impact the ability to make deliveries but on an acceptable scale
    - Some legal and/or financial exposure
    - Short term adverse impact on reputation or image
- **Low:**
    - No effect on human health or the environment
    - No significant impact on business
    - No damage significant legal or financial exposure
    - No effect on human health or the environment

Back to Document

Appendix E

Management of Change Documentation

The following items should be captured on a form or other document:

- ✓ Facility/Location
- ✓ MOC number or another designator
- ✓ ID or unit number or description
- ✓ Line segment or description of asset such as valve number, tag numbers, etc.
- ✓ Effective date and time of change
- ✓ Temporary or permanent change
- ✓ Change requested by
- ✓ Date of request
- ✓ Description of change
- ✓ Process owner' representative
- ✓ Type of change (technical, procedural, organizational, etc.)
- ✓ Reviewers
- ✓ Process checklist steps for pre-implementation, completed date and person
- ✓ Approved or rejected, reason for rejection, date, person rejecting
- ✓ Process checklist steps for post-implementation, completed date and person
- ✓ Authorizing/approving person and date

Back to Document

Appendix F

Sample Management of Change Procedure - Construction Projects

1. Purpose

This procedure sets out the administrative requirements, responsibilities and approval process for field changes to construction projects to account for budget, schedule and scope changes.

a. The objective of this procedure is to ensure that:
   1. Significant changes in scope to construction projects receive appropriate review and approval prior to being implemented. These include but are not limited to changes resulting from:
      a. Field Conditions
      b. Scope Change
      c. Design Change
      d. Personal and Process Safety Issues
   2. Construction project changes are identified, recorded and approved. The Change Control Procedure is implemented from the time a change is identified through implementation of the change.

b. This procedure applies to the following projects:
   1. All Managed Projects (Including Complex Design Projects)
      a. Complex Design Projects Category 3 changes prior to issuance of construction drawings.
      b. Complex Design Projects after construction drawings have been issued: As specified in section 5.1
   2. All standard Projects (Non-complex Design Projects) with estimates exceeding $100,000

Exceptions to this procedure to accommodate business or operational needs shall be approved by the Engineering Executive with responsibility for the Construction Process and documented on the Project Change Order Form (Attachment 1)

This procedure does not cover changes to the approved detailed gas design drawings or established gas work methods, policies and construction standards/drawings. Changes to detailed Project Engineering drawings are referred to Project Engineering for review and approval and may require a Management of Change (MOC) in accordance with Process Safety Management of Change Protocols. Changes to Gas Work Methods, Policies and Construction Standards are governed by the Governance Policy and are reviewed and approved prior to field Implementation.

2. Responsibilities

Manager of Complex Construction, Project Manager or Regional Construction/Field Ops Manager or designee shall be responsible for:

- Initiating Change Orders as necessary when not initiated by others
- Ensuring approvals are obtained as necessary.
- Advising Process Director or Regional Construction Director of any impact of Change Orders on project design and schedule.
- Obtaining necessary documentation from contractors on Change Orders.
- Approving non-complex design project Category 1 and Category 2 Change Orders not approved by Engineering or Supervisor/Field Construction Coordinator.
- Submitting for approval complex design project Category 1 and Category 2 Change Orders to Project Engineering & Design as required.
- Initiating, as required, reviewing and submitting Category 3 Change Orders for review and approval to Network Strategy and Regional Construction Directors.
- Maintaining Project Change Order Forms and Change Control Log in the Work Order/Project Folder and or project electronic data base

Construction & Maintain Supervisor / Field Construction Coordinator (FCC) or designee shall be responsible for:

- Initiating Project Change Order Forms for Category 1, 2 and 3 Change Orders as necessary.
- Completing Contractor Information, Contract Information, Change Order Category, Project Accounting and Change Notification sections of Change Order Form (Attachment 1)
- Notifying the Originating Organization, Resource Planning, Gas Construction/Maintenance, Project Management/Engineer of the requested change and record on the Change Order Form
- Approving non-complex design project Category 1 and Category 2 Change Orders that do not deviate from Construction Standards/Drawings and Gas Work Methods.
- Submitting for approval complex design project Category 1 and Category 2 Change Orders to Project Engineering & Design.
- Submitting Category 3 Change Orders for review by Process Manager, Manager of Complex Construction, Project Manager or Regional Construction Manager
- Maintaining Project Change Order Forms and Change Control Log in the Work Order/Project Folder and or project electronic data base

Project Engineering & Design, Project Management, Complex Construction, Main/Services/Replacement Engineering, Mandated Integrity Programs or designee shall be responsible for:

- Issuing Project Scope Documents and gaining approvals– See Attachment 3 Sample

Project Scope Form (Not required when established by project development documentation).

- Initiating the Change Order Form (Attachment 1) for Category 1 and Category 2 Change Orders as necessary.
- Informing Process Manager, Project Manager or Regional Construction Manager of Change Orders.
- Approving non-complex design project for Category 1 and Category 2 Change Orders initiated by Engineering
- Approving all Category 1 and Category 2 Change Orders to complex design projects
- Assisting Operation & Construction in reviewing Change Orders and Completion of Change Order Form for complex projects
- Initiating, as required, and submitting Category 3 Change Orders for approval to Network Strategy and Regional Construction Directors
- Initiating revision of construction standards/drawings and Gas Work Methods as required
- Maintaining Project Change Order Forms and Change Control Log in the Work Order/Project Folder and or project electronic data base

<u>Network Strategy, Regional Construction Project Management and Complex Construction Directors</u> shall be responsible for:

- Providing guidance and oversight, as needed, on pending Change Orders
- Approving Category 3 Change Orders

3. Personal & Process Safety

- MAH Assets – All changes to projects concerning assets within the Major Accident Hazard (MAH) portfolio (i.e., gas assets at pressures greater than or equal to 125psig, LNG assets, CNG assets) shall have a process safety risk-based review of the potential change in accordance with ***your company specific procedure***

4. Operator Qualification Required Tasks [Qualified or Directed & Observed]

Not Applicable

5. Content

5.1. Change Classification Categories

a. All changes shall be classified using the categories below:

1) Category 1 –
Definition: Does not affect the design's form, fit or function (e.g., an elbow is moved 5 ft. to avoid an obstruction) and has negligible impact to the project's scope, cost or schedule.

i. Usually identified by the construction crew and initiated by the Construction Supervisor or FCC.

ii. Approved by a Design Engineer or, for non-complex design projects only, the Construction Supervisor / FCC or Project Manager.
iii. When a change to an approved SOP is required, Gas Control is notified.

2) Category 2 -
Definition: Changes that have minor impacts to the project scope and cost and do not impact the overall project schedule.
i. These changes are within the spending limits of the project contingency and do not exceed 10% of the value of the project.
ii. Change is usually identified by the construction crew and initiated by the Construction Supervisor or FCC (e.g., for a significant offset to avoid obstructions) or requested by the Design Engineer (e.g., to either to add or replace a component), thus affecting the design.
iii. Approved by the Manager of Project Engineering & Design or, for non-complex design projects only, the Construction Supervisor /Design Engineer/ FCC or Project Manager when there are no deviations from drawings and/or Gas Work Methods.
iv. When a change to an approved SOP is required, Gas Control is notified.
v. A Change Order Form or equivalent shall be completed for all Category 2 changes.

3) Category 3 –
Definition: Changes that have a major impact to the project scope and cost and impacts the overall project schedule.
i. Has costs exceeding 10% of the value of project.
ii. It adds and/or replaces a major component and incurs significant man hours to the project. It affects the project schedule delivery date, and adds significant dollars to the project.
iii. Usually initiated by the Process Manager (Construction/Field Ops) from the Originating Organization, Program Manager, Project Manager, Design Engineer, and/or Manager of Project Engineering & Design.
iv. Requires approval by the Network Strategy Director or Regional Construction/Field Ops Director or Design Manager for Non-Complex projects
iv. When a change to an approved SOP is required, Gas Control is notified.
v. A change Order Form or equivalent shall be completed for all Category 3 changes.

5.2. In Process Design Changes

a. A design change made during the design process before the final design is issued and before long lead material is ordered is an In-Process Design Change.
   1) Project scope and design changes may be requested by any party involved in the project for a variety of reasons. Such scope or design changes shall be evaluated by the Project Engineer and approved by either the Manager of Project Engineering & Design or a designated Project Engineering & Design Team Lead. Such approvals shall be obtained prior to finalizing the design and shall be reflected on the final scope document
   2) In Process Design Changes do not require completing a Change Control Form

3) A Process Safety Risk based review of the potential change may be required in accordance with ***your company specific procedure***

5.3. Change Order Process

a. The person initiating the request has the responsibility of categorizing the change and identifying the time requirements, as well as the required approvals of the requested change in order to facilitate the project execution.

b. To avoid impacting the overall project schedule the Regional Manager of Project Engineering & Design, Process Manager, Project Manager or Regional Construction/Field Ops Manager shall be responsible for ensuring the required approvals are obtained.

c. The following inputs are recommended for preparation of project change requests.
   1) Sketches, maps, drawings, photographs, memos or other documentation specifying change
   2) Baseline plans of cost, scope, schedule, quality and risk management
   3) Description of the requested changes
   4) Project Status reports
   5) Work performance information
   6) Time reporting system reports
   7) Cost reporting system reports

d. Outputs/Deliverables for Change Order Approval
   1) A completed Project Change Order Form. See Attachment 1, Sample Project Change Order Form.
   2) Revised estimate
   3) Schedule variance analysis
   4) Preventive and Corrective Actions (If required)
   5) Forecast at completion (revised Projected Year End Calculations (PYE)

5.4. Preparation and Approval of Change Orders

a. Category 1 Change Order – Verbal Approval
   1) Initiated By: Design Engineer or Construction Supervisor/ FCC.
   2) Approved By:
      i. Complex Construction: Project Engineering & Design
      ii. Non-Complex Construction: Design Engineer, Construction Supervisor/ FCC or Project Manager

b. Category 2 Change Order
   1) Initiated and Prepared By: Design Engineer or Construction Supervisor/CO Inspector/ FCC or Project Engineering & Design Manager, Process Manager, Project Manager or Regional Construction Manager
   2) Approved By:
      i. Complex Construction - the Manager of Project Engineering & Design.
      ii. Non-Complex Construction - (no deviations from drawings and/or Gas Work Methods) the Design Engineer /Construction Supervisor / FCC or Project Manager
      iii. Non-Complex Construction – (Deviations from drawings and/or Gas Work Methods) Contact Gas Work Methods/Materials and Standards for evaluation and

approval.

c. Category 3 Change Order

Category 3 Out of Process Changes require that approvals be obtained prior to performing the work in the field

1) Initiated and Prepared By: Project Engineering & Design, Project Management or Construction Reviewed By: Project Manager, or Regional Construction/Field Ops Manager/Design Manager/Design Engineer
2) Approved By: Network Strategy and Regional Construction/Field Ops Directors or the Design Manager for Non-Complex projects.

5.5. Change Control Log

a. A Change Log shall be kept by the Program Manager, Project Manager, or Regional Construction Manager/ Design Manager for all qualifying projects. See Attachment 2, Sample Change Control Log

5.6. Records Management

a. A copy of the Change Order Form shall be filed with the project documents and/or Work Order Package and a copy sent to:
   1) Complex projects: PE&D
   2) Non-Complex Projects: Regional Construction/Field Ops Manager/Design Manager or Regional Construction Manager
   3) A copy is also be sent to the Construction Control Project Manager
b. A copy of the Change Control Log shall be filed with the Project documents and /or work Order package

6. Knowledge Base & References

Knowledge Base		References
1 - Compliance History	5 - Job Aid	1 - Regulatory – Codes
2 - Data Capture	6 - Learning & Development	2 - Technical Documents
3 - Definitions	7 - Standard Drawings	3 - Tools Catalog
4 - Document History	8 - Tools & Equipment	

Change Control #	Date:	Region: ☐ DSNY ☐ USNY ☐ MA ☐ RI
LDC Company☐	Contractor ☐	Project Information
Name:		Project Name/Address:
Yard/Barn/Location:		Originating Org: ☐ City/State Construction
Change Order Category		Purchase Order #:
☐ 1. Cat1 (Low Impact) ☐ 2. Cat 2 (Minor) (< 10% of estimate)		Project Manager:
☐ 3. Category 3 (Major) (> 10% of prior estimate)		FCC/Supervisor

Project Accounting						
Region	Activity or ACE Code	Work Order No.	Expense Type	Originating Department	Original Estimate	Change Amount or %

Description of Change:
If Temporary change, latest date before temporary change must be removed:

Reason for Change:	**☐Field Conditions**	**☐Scope Change**	**☐Design Change**	**☐Other**
Explanation:				

Change Notification			
Name	**Title/Position**	**Method**	**Date**
	Originating Organization	☐Verbal ☐ Writing	/ /
	Gas Construction/Maintenance	☐Verbal ☐Writing	/ /
	Resource Planning	☐Verbal ☐Writing	/ /
	Project Management/Engineer	☐Verbal ☐ Writing	/ /
	Other:	☐Verbal ☐ Writing	/ /

Pricing Terms				
Fixed		**Variable**		**Amount(s)**
☐ Lump Sum	☐Unitized Pricing	☐ T&E	☐ Cost Plus:_____%	**$**
		☐ Not to Exceed		**$**
☐ All-inclusive, including all required temporary & final restoration.				**$**
☐ Exclusions:				**TOTAL**
				$

Approval(s)					
Title:			**Title:**		
Print		Date	**Print**		Date
Signature	X______________________________		**Signature**	X______________________________	

Project Change Control Log

Region/Company:

Project/Work Order #:

						Approval Information		
Date Requested:	**Requested By:**	**Department:**	**Reason for Change:**	**$$ Amount of Change:**	**Recommendation:**	**Approver:**	**Date**	**Yes/No**
				0.00				

Back to Document

Guideline for Establishing & Maintaining Engineering Competency

February 24, 2023

Guideline for Establishing & Maintaining Engineering Competency

Forward

Forward

The natural gas pipeline industry has recognized the need to ensure competency of individuals performing engineering functions on pipeline facilities. To this end, Operators have implemented a variety of training and engineering development programs to maximize safety while facilitating a continuous learning culture. Today, these programs may include a strategic combination formal education, focused technical training curriculums, and *progression through experience* by incorporating on-the-job (OJT) training and mentoring components. Following recent industry incidents, NGA membership reviewed regional practices associated with the engineering design review process leading to publication of the Engineering Design Review Guideline (EDR)[1]. The EDR Guideline is intended to provide NGA Member Pipeline Operators with a framework and considerations for developing and/or assessing an existing company specific engineering design process including *competency of engineering personnel responsible for initial designs through execution of design/construction and commissioning of facilities*. While some regulatory jurisdictions took a path of requiring professional engineer review and approval of designs and associated construction work packages, other regulatory authorities took a broader perspective and now require operators to develop a more formal approach by requiring development of an Engineering Competency Written Plan to ensure engineering competency associated with elevated risk functions. These functions span a broad spectrum of gas engineering activities including design, construction, operations, and integrity management of pipeline assets.

The Guideline for Establishing and Maintaining Engineering Competency builds on the concepts and framework of the EDR however is specifically focused on addressing considerations when assessing engineering elevated risk functions specific to the design, construction, operation, and integrity of pipelines as required by recent code rule enhancements in New York State. The Guideline provides a framework for operators to consider when developing a company specific written program including training, mentoring, and evaluation process components to ensure on-going competency of personnel performing elevated risk engineering functions.

NGA publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed. Neither NGA nor any of NGA's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein, or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither NGA nor any of NGA's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

NGA publications may be used by any member desiring to do so. Every effort has been made by the NGA to assure the accuracy and reliability of the data contained in them; however, the NGA makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

NGA publications are intended to facilitate sharing of broad, proven, sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of NGA publications is not intended in any way to inhibit anyone from using any other practices.

[1] Guideline for Gas System Engineering Design Review, Northeast Gas Association, June 2020.

1. Scope & Applicability

This Guideline provides a model framework and essential elements for consideration by a member company when developing a company specific engineering training and competency program. This Guideline provides operators with guidance in assessing elevated risk engineering functions, developing, maintaining, and evaluating technical competencies needed to safely and effectively perform elevated risk engineering functions associated with natural gas pipeline systems. The Guideline incorporates key elements of the Northeast Gas Association EDR, the AGA White Paper Skills and Experience for Effectively Designing Natural Gas Systems[2] and leading practices of associated engineering, training and qualification professional organizations. The Guideline also incorporates guiding principles of API RP 1173 Pipeline Safety Management Systems.[3]

What's Covered?

- Considerations for establishing an engineering competency written program.
- Connection to Safety Management System Principles.
- Typical roles and responsibilities of engineers within a gas distribution pipeline organization.
- Assessment of elevated risk engineering functions associated with design, construction, operations and pipeline integrity.
- Education, training, mentoring and experience as critical elements of engineering competency.
- Evaluation / demonstrating competency
- Documentation & recordkeeping

In summary, this Guideline is intended to be flexible and scalable considering the size and scale of the operator/operator assets and associated design, operating, construction and integrity management practices. Essential principles are applicable to all pipeline operators, large through small. As highlighted below, the Guideline conforms with the spirit and intent of essential elements of Pipeline Safety Management Systems API RP 1173.

2. API RP 1173 Pipeline Safety Management System (PSMS) Applicability:

A pipeline safety management system is a systematic, deliberate approach to managing the safety of the workforce, the public, and the organizations assets. An essential element of a pipeline safety management system is *competence, awareness, and training*. The pipeline operator should assure that personnel whose responsibilities fall within the scope of the PSMS (including engineering functions) have an appropriate level of competence in terms of education, training, knowledge, and experience. Where engineering contractors are used to support engineering functions, the pipeline operator should evaluate the need for and assure that the engineering contractor has the appropriate level of competency for the service provided to enable a clear understanding and conformance with company specific policies, procedures, specifications, and operating practices. Where engineering contractors are used to support engineering functions, the pipeline operator must further assure that engineering contractors meet or exceed the competency requirements of the operator.

---

[2] AGA White Paper Skills and Experience for Effectively Designing Natural Gas Systems, April 8, 2019, Prepared by The AGA Operations Section, Regulatory Action & Engineering Committee.

[3] Pipeline Safety Management Systems, ANSI/API RECOMMENDED PRACTICE 1173 FIRST EDITION, JULY 2015

The pipeline operator must define the need for, and where appropriate, in accordance with a written plan, provide training to enable a clear understanding and conformance with company specific policies, procedures, specifications and operating practices. From an engineering functions perspective, a credentialed individual in an engineering discipline may not be sufficient to meet an organizations competency requirement nor the spirit of safety management system principles. It is the strategic combination of formal education, company specific training and on-the-job experience that enables a defense-in-depth strategy that ultimately minimizes safety and system risk.

Training should include refresher training and raising awareness when executing the safety assurance and continuous improvement sub-elements of RP-1173 reveal opportunities to improve processes and procedures. Records of training should be maintained. In addition, the pipeline operator should provide training and updates as necessary so that engineers and engineering contractors who have accountabilities, responsibilities, and authorities in executing the requirements of the organizations PSMS, policies, procedures and operating practices are updated and aware of:

- ✓applicable elements of the PSMS that affect their job requirements;
- ✓emerging or changing risks, problems in execution of the PSMS, and opportunities to improve processes and procedures; and
- ✓potential consequences of failure to follow processes or procedures.

Pipeline operating and engineering personnel throughout the organization should effectively communicate and collaborate with one another. Further, communicating with engineering contractors to share information that supports decision making and completing planned tasks (company specific procedures, materials, and equipment) is essential as part of job-specific education and ensuring competency. In summary, engineering competency (knowledge, skill & experience) is a core component in maximizing the effectiveness of a pipeline safety management system thereby minimizing occupational safety, process safety and pipeline safety risk. This Guideline incorporates essential elements and concepts, where applicable, included in Pipeline Safety Management Systems API RP 1173. Some of these core elements include:

- Risk Management.
- Leadership and Management Commitment.
- Safety Assurance.
- Stakeholder Engagement.
- Operational Controls.
- Competency, Awareness and Training.
- Management Review and Continuous Improvement.
- Documentation and Recordkeeping. and
- Incident Investigations, Evaluations and Lessons Learned.

3. Written Program Framework Considerations

An Engineering Competency Program is a company specific documented approach to ensuring appropriate levels of knowledge, skill, and ability necessary for individuals engaged in engineering functions while facilitating employee development and managing operational risk. Highlighted below are program elements that should be considered, regardless of size or scale of the operation.

- **Scope & Applicability –** describe company specific program scope, engineering role descriptions, progression framework and overall process approach to ensure development, competency, and assessment of those performing elevated risk engineering functions. Consider connecting aspects of your PSMS.

- **Program Description –** build out your company specific approach to developing and assessing knowledge, skill and ability of individuals performing elevated risk engineering functions. ***Describe Engineering Functions and a sub-set of those functions that are considered elevated risk based on the potential risk / consequences of AOC's associated with a specific engineering function if not performed correctly.*** This could take the form of a simplified matrix or Elevated Risk Assessment Appendix to your program. Consider mapping roles and responsibilities of individuals responsible for developing operating procedures, construction standards and design specifications associated with defined elevated risk functions.

- **Education, Training and Experience Requirements –** describe formal education and/or equivalent field experience, technical training and on-the-job experience requirements associated with a company specific engineering career path progression. This section should consider a matrix/company specific summary of requirements based on engineering functions highlighting those that are identified by an organization as elevated risk. Training requirements include organization specific environmental, health and safety requirements, operations and maintenance procedures, construction specification training, engineering design review, management of change process, operator qualification program requirements, regulatory code requirements and training covering an organization specific PSMS. Technical training may be offered internally or through a third party such as GTI Energy.

- **Building Knowledge, Skill & Ability; On-The-Job Training (OJT) and Mentoring** – this section provides guidance on integrating OJT into an Engineering Competency Program where engineers are required to build practical operational and engineering design skills, working under the direct supervision of a competent person, as a component of the engineering development process. This program component is intended to integrate technical training with working-in-practice requirements and more specifically, ensure those performing elevated risk engineering functions have a sense of situational awareness and potential abnormal operating conditions which may result during execution of day-to-day operations associated with these functions.

- **Demonstrating Competency –** provides a description of how an organization assesses and measures engineering competency and may include metrics such as formal testing in a specific subject matter area, successfully obtaining third party certifications, hours of practical on-the-job experience and working under direct supervision. Annual employee performance reviews may also be used as a competency demonstration metric provided the review integrates technical competency goals.

- **Engineering Competency Program Continuous Improvement –** this section of the program describes annual program performance reviews, incorporation of annual expert training to address MOC issues and lessons learned from individual performance associated with operations, design, construction work package execution, findings associated with integrity management programs, incident and near-miss investigations and regulatory findings associated with elevated risk engineering functions. Program continuous improvement assessments should also integrate audit and QA/QC program findings where appropriate.

- **Documentation & Recordkeeping –** describes a company specific documentation and recordkeeping process to document technical training, OJT experience, third party certifications and continuing education credit hours through approved Workshops, attendance in seminars, meetings, internal technical training, and other learning / performance demonstration opportunities. Documentation and recordkeeping should enable demonstration of individual and organization goals of engineering competency are being achieved and maintained. Documentation and recordkeeping practices may include maintaining a log or spreadsheet of an individual's training, experience, and certifications, or for larger organizations, may include use of a more sophisticated Learning Management System (LMS) approach.

NOTE: An Engineering Competency Written Program *need not be overly complex*. The goal is to provide a scalable, measurable, organization specific framework to ensure those carrying out elevated risk engineering functions are technically competent and have necessary experience, as determined by the operator, to minimize the risk of unintended consequences.

4. Typical Engineering Roles & Responsibilities

An Engineering Competency Program is highly dependent on an individual's knowledge, skill, and ability. However, a successful program is also dependent on incorporating a layered process-based approach to performing elevated risk engineering functions that ensures engagement of subject matter experts (SME's) across an organization. While an operator may have different titles for the roles described below, the hierarchy provides an example of a layers-of-protection approach to ensuring competency across the organization.

4.1 Engineering Executive

The Executive sets the tone for the larger organization, procures necessary resources, and manages people, projects, programs, and budgets in the engineering organization. The Executive may or may not be directly involved in performing elevated risk functions or the approval process for designs. The Executive should ensure comprehensive Engineering Competency Program requirements and processes are being conformed with. The Executive should ensure a comprehensive engineer training program is established and continuously updated. The Executive should emphasize and encourage a questioning attitude, collaboration, robust management of change and documentation. The Engineering Executive typically has 6-8 years of progressive responsibility and leadership in gas operations management, engineering, or construction.

4.2 Chief Engineer/Engineering Director

This position has authority for all final engineering reviews and sign offs for all design types (standard, complex non-standard, etc.) and in some cases, directly reviews more complex elevated-risk designs and associated engineering functions. The scope of this role may include final review of elevated risk engineering functions, policies associated with design, approvals, management of change, process safety and pre-startup review policies. This position is typically held by an engineering Director or Executive within the organization and is a Licensed PE with appropriate gas engineering design, construction, and operational experience (typically a minimum 5 years practical experience) or in lieu of a PE, an engineer in an appropriate discipline with more extensive construction and operational experience (typically greater than 8 years practical experience).

4.3 Technical Expert/Professional Engineer (PE) with Elevated Risk Engineering Function / Gas System Design Experience

This position has delegated authority by the Chief Engineer/Engineering Director (if the role exists within an organization) for approval of designated elevated risk engineering functions and standard designs. Approves all non-standard designs prior to approval of the Chief Engineer/Engineering Director and reviews and approves all gas work methods and procedures, including design and construction standard drawings, policies, and procedures. The Technical Expert typically has a PE with a minimum of 3-5 years of day-to-day gas engineering and operational experience; or in lieu of a PE, equivalent competency including extensive design, construction, and operational experience. Typically, this means greater than 6 years of practical experience with successful completion of related subject matter continuing education coupled with 2 years of design and elevated risk engineering functions focus.

4.4 Engineering Supervisor/Manager

This position is responsible for a group/team of engineers involved in the design, construction, operations and/or integrity management engineering. The Engineering Manager/Supervisor coordinates execution of elevated risk functions with a focus on ensuring a balanced approach to mentoring and continuous learning, design approvals and integration of SME input from other departments and stakeholder groups within the organization. The Engineering Manager/Supervisor is typically an engineer with 3-5 years of system design, construction and/or operational experience however may include individuals with advanced gas system design, construction or operational experience and associated training in lieu of formal engineering secondary education. This position may include successful completion of a Gas Engineering Certificate Program and/or Continuing Education Program.

4.5 Design, Construction, Operations and Integrity Management Engineers/Competent Person(s)

A *competent person* for purposes of this document is defined as the design, construction, operations or integrity management engineer, or individual that serves a technical role with appropriate gas system design, construction or operational experience in lieu of formal engineering secondary education, involved in elevated risk engineering functions. This position typically requires a minimum of 1-3 years practical experience in gas engineering functions working in coordination with more experienced engineers or SME's commensurate with the complexity of the design or engineering function. The Competent Person should demonstrate gas system design competency through documented education in an appropriate engineering discipline and/or appropriate experience and training such as successful completion of a Gas Engineering Certificate and/or Contineuing Education Program, participation in appropriate OJT training and/or mentoring programs.

5. Guidance for Assessing Company Specific Elevated Risk Engineering Functions

5.1 Engineering Practice and Sub-Practice Areas

Engineering practice areas can be defined in nine broad topic groups associated with New York State jurisdictional pipeline safety code requirements in 16 NYCRR Part 255 consistent with federal pipeline safety regulations in Parts 190, 191 and 192.

Specific activities, or sub-practice areas, can be defined within each practice area and generally correlate with a work function. Table 1 highlights Engineering Practice Areas and associated Sub-Practice Areas[4].

Table 1 – Engineering Practice Areas & Sub-Practice Areas

Engineering Practice Area	Typical Activities Within a Practice Area (Sub-Practice Areas)	
Pipeline & Pipeline Component Design, Material Selection, Testing	• Pipe and pipeline component material design & selection • Pipe and pipeline component testing • Pipe supports & anchors • Design and capacity of pressure relief and limiting devices • Protection of accidental overpressuring	• Permitting including land, environmental, and regional impacts • Class location • Transportation & storage of pipe and components • Compressor stations • Vaults • AOC's and sub-standard conditions
Corrosion Control	• Fundamental corrosion control design (coatings, cathodic protection, electrical isolation) • Atmospheric corrosion	• Remedial measures • Methods, tools, and technologies for monitoring, testing, and mitigation • Internal corrosion • AOC's and sub-standard conditions
Qualification of Pipeline Personnel	• OQ written plan development • Training program design • Testing design and security	• Management of records • AOC's and sub-standard conditions
Telemetry	• Supervisory Control and Data Acquisition (SCADA) systems and processes • AOC's and sub-standard conditions	• Managing communication and data from transmitters and remote equipment • Maintenance of equipment
Metering and Regulator Station Design	• Design of pressure regulation systems • Regulator sizing/capacity • Regulator station configurations • Valves, fittings, and over pressure protection in regulator stations • Odorization equipment/systems • Sensing line design and installation • Gas monitoring and security systems	• Fundamental meter sizing and configuration • Customer meter and regulation • Meter auxiliary equipment • Gas quality monitoring • Aerodynamic noise • Gas conditioning equipment (heating, filtering, scrubbing) • AOC's and sub-standard conditions
O&M, Construction Requirements	• Class location • Critical valves • MAOP • Odorization monitoring • Damage prevention • Emergency planning • Replacement, installation of mains and services • Safety inspections (leak survey & atmospheric corrosion, POE, meter	• Patrolling & line markers • Repairs to damaged pipelines • Abandonment • Uprating • Valve maintenance • Leak investigation, classification, and repair • Pressure limiting / excess flow devices. • Pipe joining methods, plastic fusion, welding, and mechanical joining practices • Emissions control

[4] Adopted from AGA White Paper Skills and Experience for Effectively Designing Natural Gas Systems, April 8, 2019, prepared by The AGA Operations Section, Regulatory Action & Engineering Committee.

	protection etc.) • Pipe and materials handling and storage • Excavation and cover • AOC's and sub-standard conditions	• Purging • Tapping pipe • Mapping systems
Construction and Operation Standards, Procedures & Specifications	• Jurisdictional regulatory requirements • Pipeline inspections, audits and QA/QC • Environmental, Health & Safety Requirements • LDAR / Emission Control processes • Engineering Design Review process • Emergency Preparedness Programs • Excavation standards • Appropriate industry standards (ASTM, ASME, ANSI, API, PPI, NFPA, NACE, AGA etc.) • AOC's and sub-standard conditions	• Part 191—Annual Reports, Incident Reports, and Safety-Related Condition Reports • Part 192—Minimum Federal Safety Standards; Subparts A through P • Part 190 - Enforcement • Incident Command Structure (ICS) • Damage Prevention Program • DIMP & TIMP Programs • OQ Requirements • PHMSA guidance materials • PSMS requirements • Mutual Aid Response
Control Room Management	• Pipeline modeling and mapping • Pressure regulation and control • Abnormal Operating Conditions (AOC) • Supervisory Control and Data Acquisition (SCADA) systems and processes	• Incident Command Structure (ICS) • Response to outages, supply interruptions and curtailments • Gas system isolation practices • Recordkeeping
Integrity / Asset Management	• DIMP/TIMP elements • Identification of HCA's • Threat identification • ECDA/ICDA	• Records • Deviation from DIMP requirements

5.2 Considerations When Assessing Company Specific Elevated Risk Engineering Functions

There are several definitions of risk. At its simplest, risk is the possibility of an adverse outcome or unintended consequence. Risk is often expressed in terms of a combination of consequences of a series of events and the associated likelihood of occurrence. The probability, frequency of occurrence and impact of an event are all factors each operator should consider in any analysis of risk including assessing engineering functions. When evaluating risk associated with engineering functions, one should consider the complexity of sub-practice areas (functions) within a practice area or a combination of functions and likelihood of potential abnormal operating conditions (AOC's)[5] including:

- Unplanned escape of product from a pipeline.
- Fire or explosion.
- Unplanned pressure deviation (e.g., increase, decrease, high, low, absent).
- Unplanned flow-rate deviation (e.g., high flow, low flow, no flow).

[5] ASME B31Q-2021

- Pipeline damage (e.g., excavation damage, inappropriate handling of pipe/pipeline components during storage or installation).
- Activation of a safety device(s) other than during planned testing (e.g., pressure relief, emergency shutdown, high-pressure shutdowns, case pressure shutdowns, high-temperature shutdowns).
- Unplanned status change (e.g., unit startup, unit shutdown, valve open, valve close, without being directed to do so).
- Interruption or failure of communications, control system, or power. and
- Inadequate odorization or reports of gas odor.

Company specific elevated risk engineering functions can be derived from assessment of the abovementioned engineering practice area activities which are directly related to pipeline safety code. In some jurisdictions code sections are identified as *elevated risk* for purposes of compliance assessments. In New York State for example, the New York State Department of Public Service (NYSDPS) has identified elevated risk pipeline safety code sections (Appendix A). Activities conducted within these code sections should be considered when assessing individual company elevated risk engineering functions.

More specifically, an operator should consider defined engineering roles within an organization that have responsibility for developing, reviewing, and approving design, construction and operating procedures, standards, specifications, and integrity programs. Individuals in these roles performing defined elevated risk engineering functions should be included in the Engineering Competency Program.

6. Training, Mentoring & Education Process Considerations

An engineering competency program combines specific technical and functional competencies that are unique to the organization, its facilities, equipment, procedures, and job roles. It is recognized that a "one size fits all" program does not make sense in establishing and maintaining engineering competency however there are core elements of formal education and/or OJT experience coupled with demonstrated knowledge of company specific procedures common to all program approaches. For elevated risk engineering functions, a strategic balance of formal education, training and experience are key to influencing human behaviors and *mistake proofing* decisions and actions. Highlighted below are examples of defining competency requirements associated with engineering roles within an organization.

6.1 Formal Education, Gas Engineering Training and Certification

Gas Distribution (Design, Construction, Operations, and Integrity Management Engineering)

Training/coursework/experience to demonstrate competency in the gas distribution engineering discipline is typically operator defined. The following knowledge domains, appropriate for a defined role, scope of work and responsibility should be considered for associated elevated risk functions:

- Overview of the Natural Gas Industry (exploration and production, gathering, transmission, distribution, utilization of natural gas)
- Properties of natural gas
- Federal and state pipeline safety regulations, consensus codes and standards
- Organization operating policies and procedures (including PSSR's, PSMS, SOP process)
- Material properties and design considerations (plastic, steel, cast iron, wrought iron)
- MAOP design considerations

- Distribution pipeline design (buried piping systems, mains and services)
- Distribution pipeline repair methods and considerations
- Pipeline crossing design (highways, bridges, culverts, railroads, waterways)
- Pipeline construction practices (open trench, trenchless installation methods)
- Welding of steel pipe
- Destructive and non-destructive testing of weld joints
- Joining of plastic pipe
- Destructive and non-destructive testing of plastic joints
- Mechanical joining
- Pipeline tapping, by-passing and installation of stopples
- Pressure testing
- Purging
- Uprating
- Odorization
- Fundamentals of corrosion and cathodic protection
- Pipeline coating systems
- Gas measurement principles
- Meter types, applications, sizing, and selection for distribution applications
- Pressure regulation and over-pressure protection fundamentals
- Regulator types, sizing, and selection for distribution applications
- Regulator control instability causes and cures
- Over-pressure protection methods, sizing, and selection for distribution applications
- Design of residential and commercial measurement and pressure control runs
- Design of large commercial and industrial measurement and pressure control runs
- Design of district regulator stations
- Gas conditioning requirements and equipment selection for distribution applications
- Noise considerations for pressure regulating stations
- System loads and methods for determining design loads
- Fundamentals of gas control, SCADA and telemetry
- Gas flow calculations, pipe sizing, hydraulic modelling, and network analysis
- Permitting, environmental protection, easements, surveying
- Overview of GIS systems, maps, record keeping systems
- OSHA and other government design, construction and safety standards
- The potential for job function Abnormal Operating Conditions (AOC's)

Recommended Formal Education Courses:

Competency may be demonstrated by formal documented OJT experience and/or a combination of formal OJT experience, course work and continuing education courses. The course knowledge domains provided by an operator sponsored training program utilizing an industry recognized curriculum is one option; or a training/certificate program provided by a recognized industry organization, equipment, or material manufacturer, using an operator approved curriculum. OJT experience working under the supervision of a competent person(s) in a mentoring relationship should be documented to ensure company specific requirements are achieved.

A comprehensive course curriculum and certificate of completion supported by examination are highly recommended to substantiate successful completion of coursework. In addition, college equivalency or continuing education hours should be provided if applicable.

As one example, the Gas Technology Institute (GTI) offers the following programs:

- Fundamentals of Gas Distribution (online course)
- Gas Distribution Engineering 1
- Gas Distribution Engineering 2
- Pipeline Safety Regulatory Compliance
- Measurement & Regulator Station Design
- Gas Distribution Operations
- Registered Gas Distribution Professional
- GTI Competent Engineer Exam

Gas Transmission (Design, Construction, Operations, and Integrity Management Engineering)

In addition to the Gas Distribution knowledge domains highlighted above, supplemental transmission system specific training/coursework/experience to demonstrate competency in a Transmission Engineering discipline should consider the following knowledge domains (as required by assets considered in a specific design, construction project, operations and integrity program):

- Transmission pipeline design and pipeline repair methods and considerations
- Smart pig design considerations for the pipeline system
- Design of pig launching and receiving facilities
- Design of automatic shutdown and remote-control valve systems (ACV & RCV)
- Pressure testing of transmission pipelines
- Uprating of transmission pipelines
- Purging of transmission pipelines
- Meter types, applications, sizing and selection for transmission applications
- Energy measurement and gas quality monitoring instrumentation
- Regulator types, sizing, and selection for transmission applications
- Regulator control instability causes and cures
- Over-pressure protection methods, sizing, and selection for transmission applications
- Design of industrial measurement and pressure control runs
- Design of gate stations
- Design of gas heating systems
- Design of compressor stations
- Odorization requirements, systems and design considerations
- Gas conditioning requirements and design considerations for transmission applications
- Noise considerations for pressure regulating stations and compressor stations

NGA
NORTHEAST GAS ASSOCIATION

Recommended Formal Education Courses:

Competency may be demonstrated by formal documented OJT experience and/or a combination of formal OJT experience, course work and continuing education courses. The course work knowledge domains may be provided by an operator sponsored training program utilizing an industry recognized, operator approved curriculum; or a training/certificate program provided by a recognized industry organization, equipment, or material manufacturer, using an operator approved curriculum.

A comprehensive course curriculum and certificate of completion supported by examination are highly recommended to substantiate successful completion of coursework. In addition, college equivalency or continuing education hours should be provided if applicable. OJT experience working under the supervision of a competent person(s) in a mentoring relationship should be documented to ensure company specific requirements are achieved.

As one example, the Gas Technology Institute (GTI) offers the following supplemental programs for Transmission Engineers:

- Gas Transmission Operations
- Transmission Pipeline Design & Construction
- Compressor Station Design
- Certified Gas Transmission Professional Certification Program
- GTI Competent Engineer Exam.

Gas Processing (Design, Construction, Operations, and Integrity Management Engineering)

In addition to the above applicable coursework, supplemental training/coursework/ OJT experience to demonstrate competency in the Gas Processing discipline should include the following knowledge domains as appropriate for the design under review:

- Design, Construction and Operation of compressed gas fueling stations;
- Natural gas processing facilities including liquefaction cycles, tank storage systems and vaporization systems;
- Portable LNG vaporization facilities;
- Gas conditioning systems (beyond the scope of filters, strainers and heaters included in Gas Transmission and Distribution Competencies);
- Portable pipeline compressed natural gas injection/supply systems;

Recommended Formal Education Courses:

Competency may be demonstrated by formal documented OJT experience and/or a combination of formal OJT experience, course work and continuing education courses. The course knowledge domains provided by internal operator sponsored training programs utilizing an industry recognized, operator approved curriculum are one option; or a training/certificate program provided by a recognized industry organization, equipment, or material manufacturer, using an operator approved curriculum. Examples of some industry organizations and relevant courses are provided below.

A comprehensive course curriculum and certificate of completion supported by examination are highly recommended to substantiate successful completion of coursework. In addition, college equivalency or continuing education hours should be provided if applicable.
As one example, the Gas Technology Institute (GTI) offers the following programs:

- Compressor Station Design
- LNG Plant Design and Operations
- GTI Competent Engineer Exam

Additionally, the Gas Processors Association (GPA) Midstream Association offers the following programs:

- GPA offers a comprehensive course and certification in the use of the GPSA Engineering Data Book; an industry recognized technical reference related to determining natural gas operating and design parameters for gas processing facilities

6.2 Company Specific Training, Policies, Standards, Procedures and Specifications

In addition to formal education, gas engineering training and certification, training in the use of company specific policies, standards, procedures, and specifications is yet another essential component of to ensuring engineering competency. Typically, these documents build on specific regulatory code requirements while addressing specific design, construction, and operating requirements unique to company specific assets. An engineering competency program must incorporate both formal training in company specific procedures applicable to the role and engineering functions being performed. This training should specifically address the potential risk for AOC's and other potential risks; both immediate and long-term unintended consequences if execution of elevated risk engineering functions deviates from prescribed instructions and guidance highlighted in these documents. Lastly, the engineering competency program should incorporate a prescribed formal review period and address management of change (MOC) associated with company specific engineering design, construction, operations and integrity management documents.

6.3 Mentoring and On-The-Job (OJT) Training

The value of hands-on experience through mentoring and OJT should not be underestimated in establishing and maintaining engineering competency. There are several OJT frameworks that should be considered when developing an engineering competency program including (additional OJT reference material is included in Appendix C):

- ✓ **Self-instruction training –** employee training & development courses accessed anytime by employees, and they go through at their own pace (eLearning Modules).

- ✓ **Orientation –** is very common and typically referred to as on-boarding. Whenever an engineer's role in the organization changes, new-role orientation should be considered as part of the overall competency development program. Orientation may include a formal review of associated company specific procedures, expectations of the employee in the new role and address additional policies, tools and equipment utilization.

- ✓ **Co-worker training –** an informal mentoring relationship where an experienced, competent individual receives knowledge from colleagues who are in the same role. This type on mentoring is unique because there is no hierarchy, simply trained employees making each other better.

- ✓ **Shadowing –** somewhat similar to co-worker training, however this is a very hands-on approach to competency development where a subject matter expert (SME) shows the less experienced employee what to do and then allows the employee to try it under supervision. Throughout the shadowing process, the SME usually provides suggestions and feedback to advance the education transfer process.

- ✓ **Job-rotation –** involves employees doing different jobs within a defined career path framework offering the employee knowledge of the entire engineering design, construction, operations, or integrity management process. In some job rotation scenarios, engineers are also required to build-on their formal education and training providing a more comprehensive perspective of associated elevated risk engineering functions. A job rotation may also incorporate additional shadowing or co-worker training opportunity and should include an orientation component.

6.4 Workshops, Industry Certifications and Continuing Education (CE)

Continuing education is another element of ensuring and maintaining engineering competency. Regardless of credentialed engineering status, and mandated requirements for professional development hours (PDH's), engineering competency programs should consider a role specific continuing education component of maintaining competency. Similar to formal requirements of Professional Engineers, it is important for those performing elevated risk engineering functions to maintain engineering knowledge and improve skills. Continuing education may be formal courses with defined PDH's or may be less formal however off knowledge-value such as technically focused workshops, technical organization certifications (ASME, ASTM, AMPP (formally NACE), API etc.), and manufacturers equipment, materials training / refresher sessions. CE may also include industry conference attendance where specific engineering design, construction, operations and integrity management issues and leading practices / lessons learned are discussed such as the NGA DOT Part 192 Regulations Workshop.

6.5 Company Specific Core Competency Training/Process Consideration Summary

Highlighted below are company specific core training areas that should be considered for engineers performing elevated risk engineering functions. Training may be accomplished as part of an on-boarding process through self-paced eLearning modules or instructor lead training and competency classes. Core topic areas include:

- How to Access O&M Procedures, Construction Specifications and Policies.
- Emergency Response Plan.
- Damage Prevention Plan.
- Pipeline Public Awareness Program.
- PSMS.
- Management of Change Policy.
- Environmental, Health & Safety Plan, Policies, Procedures.
- Operator Qualification Program.
- Integrity Management Program Awareness.
- Engineering Design & Review Policy (EDR). and
- DIMP & TIMP.

NGA
NORTHEAST GAS ASSOCIATION

7. Demonstrating Competency, Documentation and Evaluation Process Considerations

The operator should develop a company specific, documented approach to demonstrate competency associated with elevated risk engineering functions as part of an engineering competency program. Considerations include:

- documentation of an individual's formal education;
- cataloging experience in various engineering roles/positions/progressions;
- developing a competency matrix establishing a company specific summary of requirements for formal education, training in policies, procedures, construction standards and integrity management plans, associated OJT requirements specifically addressing company defined elevated risk engineering functions and associated activities;
- integration of specific education, experience, and skill development goals in performance review measures;
- developing a formal approach to documenting individual OJT, for example, a "book of repetitions" approach where skill and experience in specific elevated risk engineering functions is memorialized (purging mains, tapping pipelines, assessing internal corrosion of a pipeline, installation of pipe, design of a district regulator station etc.);
- documentation of continuing education, annual O&M procedure reviews "refresher training", Operator Qualification Tasks if applicable.
- certification through third party exams (GTI Competent Engineer Program etc.)

7.1 Examples of Defined Education, Training and Experience for Engineering Roles that Demonstrate Competency

Highlighted below are examples of education, training, and experience for defined engineering roles.

NOTE: These are examples of typical process roles however these roles may not be present in every company. The company specific engineering competency program should define roles and responsibilities and engineering development progression associated with elevated risk functions.

Process Responsibility: Engineering Executive/Director (Design, Construction, Operations, and Integrity Management)

Description: overall functional area engineering design, construction, operations and/or integrity management plan end-to-end process responsibility including personnel responsible for gas system design, construction, operations and/or integrity management program implementation from concept through final approval, construction execution and commissioning of facilities. Additional responsibilities include overall team leadership and process conformance, compliance with all local, state and federal design, construction, O&M, and integrity management implementation conformance with applicable company standards, work methods, procedures and policies.

Required Education: B.S. in an appropriate Management/Business Administration or Engineering Discipline, advanced degree, P.E. or equivalent preferred however not required.

Gas System Experience: 6-8 years of progressive responsibility and leadership in gas operations management, engineering, or construction.

Additional Recommended Education / Certification: Advanced professional training and continuing education related to pipeline operations regulatory requirements, gas engineering design, construction and operations and Pipeline Safety Management Systems (PSMS) leadership, overall multi-disciplinary gas business background.

Process Responsibility: Technical Expert / Professional Engineer (PE) with Gas System Design Experience

Description: responsible for impartial review independent of the Design Engineer or Engineering Project Development Team (Design Engineer(s), SME Review and Engineering Manager Review). Review typically reserved for complex, site/project specific non-standard engineering designs typically performed by a Licensed Professional Engineer (PE) with demonstrated subject matter experience, or documented extensive gas system design, operations and/or construction experience OR Equivalent Technical Expert.

Required Education: B.S. in an appropriate Engineering Discipline, advanced degree preferred, P.E. or equivalent Technical Expert (which includes successful completion of the Registered Gas Distribution Professional Program and/or the Certified Gas Transmission Professional (CGTP) Program) or comparable gas system design review certification from a company approved continuing education provider.

Gas System Experience: With a P.E., minimum 3-5 years practical gas system design, operations and/or construction experience. P.E. equivalent competency (in lieu of a PE) includes extensive design, construction, and operational experience. Typically, this means greater than 6 years of practical experience with successful completion of related subject matter continuing education coupled with 2 years of design approval focus.

Additional Recommended Education / Certification: For P.E. equivalent status, successful completion of the GTI Registered Gas Distribution Professional Program AND/OR Certified Gas Transmission Professional Program (CGTP) or comparable gas system design certification program from a company recognized continuing education provider. Advanced professional training and continuing education related to subject matter under review including gas processing facility design, construction and operational reviews.

Process Responsibility: Engineering Manager / Supervisor

Description: engineering team supervisory role, responsible for engineering design, construction, operations and/or integrity management area(s) and for engineer leadership and development. Responsibilities include ensuring engineering design, construction, operations, integrity management procedure, specification and process conformance with designs, construction execution, facility operations and maintenance and integrity management process implementation. In addition, technical oversight, and approvals in accordance with all local, state, and federal code requirements, company specific procedures and industry acceptable practices.

Required Education: B.S. in an appropriate Engineering Discipline, advanced degree preferred, however may include individuals with advanced gas system design, construction or operational experience and associated training in lieu of formal engineering secondary education.

Gas System Experience: 3-5 years practical design approval experience with an appropriate Degree in an engineering discipline, 5-10 years' experience without a an engineering degree with appropriate company specified training.

Additional Recommended Education / Certification: Participation in GTI Registered Gas Distribution Professional Program or other professional gas system coursework working towards Certificate with Operations or Engineering focus.

Process Responsibility: Design, Construction, Operations, and Integrity Management Engineer / Competent Person(s)

Description: a variety of design, construction, operations, and integrity management roles with varied responsibilities depending on the specific defined role including development and review of engineering designs, development of work packages, execution of construction work packages, operations and inspection of gas pipeline facilities and development/assessment/continuous improvement of pipeline integrity management programs. Development/review of O&M procedures, construction specifications, training and qualification programs, emergency plans, public awareness programs and safety management system implementation. Participate in SME review teams focused on design operability, constructability, pipeline safety and system reliability.

Required Education: B.S. in an appropriate Engineering Discipline preferred, OR practical gas operations, construction, integrity management and/or gas control experience as specified below.

Gas System Experience: 1-3 years practical design, construction, operating and/or integrity management experience with B.S., 4-8 years related operational/gas construction experience without an engineering degree.

Additional Recommended Education / Certification: Participation in GTI Registered Gas Distribution Professional Program or other professional gas system coursework working towards Certificate with Operations or Engineering focus. For non-degree SME's, professional training and continuing education related to subject matter under review or other gas system coursework.

NOTE: Demonstrating competency includes an integrated approach to ensure appropriate knowledge, skill and ability to manage and perform elevated risk engineering functions. This typically includes an ability to demonstrate competency through an integrated approach and strategic combination of formal education, training, and experience.

Appendix:

A. **16 NYCRR Part 255 Code Section Overall Risk Ranking by NYSDPS**

B. **OJT Leading Practice Considerations**

Appendix A - 16 NYCRR Part 255 NYSDPS Risk Ranking

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	14	(a)	Conversion to Service Subject to this Part	High
16	III	C	255	14	(b)	Conversion to Service Subject to this Part	Other
16	III	C	255	17	All	Preservation of Records	Other
16	III	C	255	53	All	Materials - General	High
16	III	C	255	65	All	Materials - Transportation of Pipe	High
16	III	C	255	103	All	Pipe Design - General	High
16	III	C	255	143	All	Design of Pipeline Components - General Requirements	High
16	III	C	255	159	All	Design of Pipeline Components - Flexibility	High
16	III	C	255	161	All	Design of Pipeline Components - Supports and Anchors	High
16	III	C	255	163	All	Compressor Stations - Design and Construction	Other
16	III	C	255	165	All	Compressor Stations - Liquid Removal	Other
16	III	C	255	167	All	Compressor Stations - Emergency Shutdown	High
16	III	C	255	169	All	Compressor Stations - Pressure Limiting Devices	High
16	III	C	255	171	All	Compressor Stations - Additional Safety Equipment	Other
16	III	C	255	173	All	Compressor Stations - Ventilation	High
16	III	C	255	179	All	Valves on Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	181	All	Distribution Line Valves	High
16	III	C	255	183	All	Vaults - Structural Design Requirements	High
16	III	C	255	185	All	Vaults - Accessibility	Other
16	III	C	255	187	All	Vaults - Sealing, Venting, and Ventilation	Other
16	III	C	255	189	All	Vaults - Drainage and Waterproofing	High
16	III	C	255	190	All	Calorimeter or Calorimixer Structures	Other
16	III	C	255	191	All	Design Pressure of Plastic Fittings	Other
16	III	C	255	193	All	Valve Installation in Plastic Pipe	Other
16	III	C	255	195	All	Protection Against Accidental Overpressuring	High
16	III	C	255	197	All	Control of the Pressure of Gas Delivered from High Pressure Distribution Systems	High
16	III	C	255	199	All	Requirements for Design of Pressure Relief and Limiting Devices	High
16	III	C	255	201	All	Required Capacity of Pressure Relieving and Limiting Stations	High
16	III	C	255	203	All	Instrument, Control, and Sampling Piping and Components	Other
16	III	C	255	225	All	Qualification of Welding Procedures	High
16	III	C	255	227	All	Qualification of Welders	High
16	III	C	255	229	All	Limitations On Welders	Other
16	III	C	255	230	All	Quality Assurance Program	Other
16	III	C	255	231	All	Welding - Protection from Weather	High
16	III	C	255	233	All	Welding - Miter Joints	High
16	III	C	255	235	All	Preparation for Welding	High
16	III	C	255	237	All	Welding - Preheating	Other
16	III	C	255	239	All	Welding - Stress Relieving	Other
16	III	C	255	241	(a),(b)	Inspection and Test of Welds	High
16	III	C	255	241	(c)	Inspection and Test of Welds	Other
16	III	C	255	243	(a),(b),(c),(d),(e)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	243	(f)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	244	All	Welding Inspector	High
16	III	C	255	245	All	Welding - Repair or Removal of Defects	High
16	III	C	255	273	All	Joining of Materials other than by Welding - General	High
16	III	C	255	279	All	Joining of Materials other than by Welding - Copper Pipe	High
16	III	C	255	281	All	Joining of Materials other than by Welding - Plastic Pipe	High
16	III	C	255	283	All	Plastic Pipe - Qualifying Joining Procedures	Other
16	III	C	255	285	(a),(b),(d)	Plastic Pipe - Qualifying Persons to make Joints	High
16	III	C	255	285	(c)(e)	Plastic Pipe - Qualifying Persons to make Joints	Other
16	III	C	255	287	All	Plastic Pipe - Inspection of Joints	Other
16	III	C	255	302	All	Notification Requirements	High
16	III	C	255	303	All	Compliance with Construction Standards	High
16	III	C	255	305	All	Inspection - General	High
16	III	C	255	307	All	Inspection of Materials	High
16	III	C	255	309	All	Repair of Steel Pipe	High
16	III	C	255	311	All	Repair of Plastic Pipe	High
16	III	C	255	313	(a),(b),(c)	Bends and Elbows	High
16	III	C	255	313	(d)	Bends and Elbows	Other
16	III	C	255	315	All	Wrinkle Bends in Steel Pipe	High
16	III	C	255	317	All	Protection from Hazards	Other
16	III	C	255	319	All	Installation of Pipe in a Ditch	Other
16	III	C	255	321	All	Installation of Plastic Pipe	High
16	III	C	255	323	All	Casing	Other
16	III	C	255	325	All	Underground Clearance	High
16	III	C	255	327	All	Cover	Other
16	III	C	255	353	All	Customer Meters and Regulators - Location	Other
16	III	C	255	355	All	Customer Meters and Regulators - Protection from Damage	Other
16	III	C	255	357	(a),(b),(c)	Customer Meters and Service Regulators - Installation	Other
16	III	C	255	357	(d)	Customer Meters and Service Regulators - Installation	High
16	III	C	255	359	All	Customer Meter Installations - Operating Pressure	Other
16	III	C	255	361	(a),(b),(c),(d)	Service Lines - Installation	Other
16	III	C	255	361	(e),(f),(g),(h),(i)	Service Lines - Installation	High
16	III	C	255	363	All	Service Lines - Valve Requirements	Other
16	III	C	255	365	(a),(c)	Service Lines - Location of Valves	Other
16	III	C	255	365	(b)	Service Lines - Location of Valves	High
16	III	C	255	367	All	Service Lines - General Requirements for Connections	Other
16	III	C	255	369	All	Service Lines - Connections to Cast Iron or Ductile Iron Mains	Other
16	III	C	255	371	All	Service Lines - Steel	Other
16	III	C	255	373	All	Service Lines - Cast Iron and Ductile Iron	Other
16	III	C	255	375	All	Service Lines - Plastic	Other
16	III	C	255	377	All	Service Lines - Copper	Other
16	III	C	255	379	All	New Service Lines not in Use	Other
16	III	C	255	381	All	Service Lines - Excess Flow Valve Performance Standards	Other
16	III	C	255	455	(a)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	Other
16	III	C	255	455	(d),(e)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	High
16	III	C	255	457	All	External Corrosion Control - Buried or Submerged Pipelines Installed before July 31, 1971	High
16	III	C	255	459	All	External Corrosion Control - Examination of Buried Pipeline when Exposed	Other
16	III	C	255	461	(a),(b),(d),(e),(f),(g)	External Corrosion Control - Protective Coating	Other
16	III	C	255	461	(c)	External Corrosion Control - Protective Coating	High

16	III	C	255	463	All	External Corrosion Control - Cathodic Protection	High
16	III	C	255	465	(a),(e)	External Corrosion Control - Monitoring	High
16	III	C	255	465	(b),(c),(d),(f)	External Corrosion Control - Monitoring	Other
16	III	C	255	467	All	External Corrosion Control - Electrical Isolation	Other
16	III	C	255	469	All	External Corrosion Control - Test Stations	Other
16	III	C	255	471	All	External Corrosion Control - Test Leads	Other
16	III	C	255	473	All	External Corrosion Control - Interference Currents	Other
16	III	C	255	475	All	Internal Corrosion Control - General	Other
16	III	C	255	476	(a),(c)	Internal Corrosion Control - Design and Construction of Transmission Line	High

16	III	C	255	476	(d)	Internal Corrosion Control - Design and Construction of Transmission Line	Other
16	III	C	255	479	All	Atmospheric Corrosion Control - General	Other
16	III	C	255	481	All	Atmospheric Corrosion Control - Monitoring	Other
16	III	C	255	483	All	Remedial Measures - General	High
16	III	C	255	485	(a),(b)	Remedial Measures - Transmission Lines	High
16	III	C	255	485	(c)	Remedial Measures - Transmission Lines	Other
16	III	C	255	487	All	Remedial Measures - Distribution Lines other than Cast Iron or Ductile Iron Lines	Other
16	III	C	255	489	All	Remedial Measures - Cast Iron and Ductile Iron Pipelines	Other
16	III	C	255	490	All	Direct Assessment	Other
16	III	C	255	491	All	Corrosion Control Records	Other
16	III	C	255	503	All	Test Requirements - General	Other
16	III	C	255	505	(a),(b),(c),(d)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	505	(e),(h),(i)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	507	All	Test Requirements for Pipelines to Operate at less than 125 PSIG (862 kPa)	Other
16	III	C	255	511	All	Test Requirements for Service Lines	Other
16	III	C	255	515	All	Environmental Protection and Safety Requirements	Other
16	III	C	255	517	All	Test Requirements - Records	Other
16	III	C	255	552	All	Upgrading / Conversion - Notification Requirements	Other
16	III	C	255	553	(a),(b),(c),(f)	Upgrading / Conversion - General Requirements	High
16	III	C	255	553	(d),(e)	Upgrading / Conversion - General Requirements	Other
16	III	C	255	555	All	Upgrading to a Pressure of 125 PSIG (862 kPa) or More in Steel Pipelines	High
16	III	C	255	557	All	Upgrading to a Pressure Less than 125 PSIG (862 kPa)	High
16	III	C	255	603	All	Operations - General Provisions	High
16	III	C	255	604	All	Operator Qualification	High
16	III	C	255	605	All	Essentials of Operating and Maintenance Plan	High
16	III	C	255	609	All	Change in Class Location - Required Study	High
16	III	C	255	611	(a),(d)	Change in Class Location - Confirmation or Revision of Maximum Allowable Operating Pressure	Other
16	III	C	255	613	All	Continuing Surveillance	Other
16	III	C	255	614	All	Damage Prevention Program	High
16	III	C	255	615	All	Emergency Plans	High
16	III	C	255	616	All	Customer Education and Information Program	High
16	III	C	255	619	All	Maximum Allowable Operating Pressure - Steel or Plastic Pipelines	High
16	III	C	255	621	All	Maximum Allowable Operating Pressure - High Pressure Distribution Systems	High
16	III	C	255	623	All	Maximum and Minimum Allowable Operating Pressure - Low Pressure Distribution Systems	High
16	III	C	255	625	(a),(b)	Odorization of Gas	High
16	III	C	255	625	(e),(f)	Odorization of Gas	Other
16	III	C	255	627	All	Tapping Pipelines Under Pressure	High
16	III	C	255	629	All	Purging of Pipelines	High
16	III	C	255	631	All	Control Room Management	High
16	III	C	255	705	All	Transmission Lines - Patrolling	High
16	III	C	255	706	All	Transmission Lines - Leakage Surveys	High
16	III	C	255	707	(a),(c),(d),(e)	Line Markers for Mains and Transmission Lines	Other
16	III	C	255	709	All	Transmission Lines - Record Keeping	Other
16	III	C	255	711	All	Transmission Lines - General Requirements for Repair Procedures	High
16	III	C	255	713	All	Transmission Lines - Permanent Field Repair of Imperfections and Damages	High
16	III	C	255	715	All	Transmission Lines - Permanent Field Repair of Welds	High
16	III	C	255	717	All	Transmission Lines - Permanent Field Repairs of Leaks	High
16	III	C	255	719	All	Transmission Lines - Testing of Repairs	High
16	III	C	255	721	(b)	Distribution Systems - Patrolling	Other
16	III	C	255	723	All	Distribution Systems -Leakage Surveys and Procedures	High
16	III	C	255	725	All	Test Requirements for Reinstating Service Lines	Other
16	III	C	255	726	All	Inactive Service Lines	Other
16	III	C	255	727	(b),(c),(d),(e),(f),(g)	Abandonment or Inactivation of Facilities	Other
16	III	C	255	729	All	Compressor Stations - Procedures for Gas Compressor Units	High
16	III	C	255	731	All	Compressor Stations - Inspection and Testing of Relief Devices	High
16	III	C	255	732	All	Compressor Stations - Additional Inspections	High
16	III	C	255	735	All	Compressor Stations - Storage of Combustible Materials	Other
16	III	C	255	736	All	Compressor Stations - Gas Detection	High
16	III	C	255	739	(a),(b)	Pressure Limiting and Regulating Stations - Inspection and Testing	High
16	III	C	255	739	(c),(d),(e),(f)	Pressure Limiting and Regulating Stations - Inspection and Testing	Other
16	III	C	255	741	All	Pressure Limiting and Regulating Stations - Telemetering or Recording Gauges	Other
16	III	C	255	743	(a),(b)	Pressure and Limiting and Regulating Stations - Testing of Relief Devices	High
16	III	C	255	743	(c)	Regulator Station MAOP	Other
16	III	C	255	744	All	Service Regulators and Vents - Inspection	Other
16	III	C	255	745	All	Transmission Line Valves	High
16	III	C	255	747	All	Valve Maintenance - Distribution Systems	Other
16	III	C	255	748	All	Valve Maintenance - Service Line Valves	Other
16	III	C	255	749	All	Vault Maintenance	Other
16	III	C	255	751	All	Prevention of Accidental Ignition	High
16	III	C	255	753	All	Caulked Bell and Spigot Joints	Other
16	III	C	255	755	All	Protecting Cast Iron Pipelines	High
16	III	C	255	756	All	Replacement of Exposed or Undermined Cast Iron Piping	High
16	III	C	255	757	All	Replacement of Cast Iron Mains Paralleling Excavations	High
16	III	C	255	801	All	Reports of accidents	Other
16	III	C	255	803	All	Emergency Lists of Operator Personnel	Other
16	III	C	255	805	(a),(b),(e),(g),(h)	Leaks - General	Other

16	III	C	255	807	(a),(b),(c)	Leaks - Records	Other
16	III	C	255	807	(d)	Leaks - Records	High
16	III	C	255	809	All	Leaks - Instrument Sensitivity Verification	High
16	III	C	255	811	(b),(c),(d),(e)	Leaks - Type 1 Classification	High
16	III	C	255	813	(b),(c),(d)	Leaks - Type 2A Classification	High
16	III	C	255	815	(b),(c),(d)	Leaks - Type 2 Classification	High
16	III	C	255	817	All	Leaks - Type 3 Classification	Other
16	III	C	255	819	(a)	Leaks - Follow-Up Inspection	High
16	III	C	255	821	All	Leaks - Nonreportable Reading	High
16	III	C	255	823	(a),(b)	Interruptions of Service	Other
16	III	C	255	825	All	Logging and Analysis of Gas Emergency Reports	Other
16	III	C	255	829	All	Annual Report	Other
16	III	C	255	831	All	Reporting Safety-Related Conditions	Other
16	III	C	255	905	All	High Consequence Areas	High
16	III	C	255	907	All	General (IMP)	Other
16	III	C	255	909	All	Changes to an Integrity Management Program (IMP)	Other
16	III	C	255	911	All	Required Elements (IMP)	High
16	III	C	255	915	All	Knowledge and Training (IMP)	High
16	III	C	255	917	All	Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	High
16	III	C	255	919	All	Baseline Assessment Plan (IMP)	High
16	III	C	255	921	All	Conducting a Baseline Assessment (IMP)	High
16	III	C	255	923	All	Direct Assessment (IMP)	High

Appendix B - The Value of OJT[6]

No matter what business you are in, on-the-job training (OJT) is an essential part of any employee's onboarding and development. While the primary benefit of using OJT is to use existing resources to train employees to do their jobs, it also has other organizational value. For example, studies have shown that on-the-job training is strongly related to greater creativity and innovation, the achievement of organizational objectives, and improvement in overall work quality. Other types of training methods, such as simulations, classroom training, and online training are all useful for some types of training (i.e., safety training, product knowledge, etc.), but research suggests some 80 to 90 percent of an employee's work skills are learned through OJT.

Advantages of OJT

For most business owners and managers, OJT programs are attractive because they can be implemented quickly and easily. Compared to other training methods OJT is also more cost-effective, costing almost a third of what outside training programs cost. While cost is one of the most important benefits of OJT, there are numerous other advantages, including:

- **OJT allows employees to experience the actual work activities of the job.** Because OJT takes place in the work environment, it also includes aspects of the company's cultural, climate, and normative behavior. These are organizational aspects other methods of training are unable to replicate.
- **OJT provides individualized attention and mentoring.** When a new employee begins work, more time and attention is required to coach and guide the employee's development of skills with each task. As competency improves, the intensity of supervision declines as the trainee masters the task and can perform it with limited guidance. Other training methods lack the durational and context flexibility necessary for comprehensive skill development.
- **OJT allows for different learning styles.** Some employees learn by doing, some learn through listening, while still others learn visually, and each at a different rate. On-the-job training offers individualized instruction that accommodates different learning styles and learning rates.
- **OJT offers flexibility in conducting training.** Outside training, simulations, and even online training often depend on specific training schedules. But considerations such as third shifts, employee absences, and other workforce concerns are not affected by on-the-job programs.
- **OJT can readily adapt to change.** Manufacturers regularly make improvements and upgrades and may even decide not to support older versions of the equipment. Likewise, production processes change depending on many operational factors. With OJT, training can be readily redesigned to reflect an employer's specific equipment, as well as changes and activities unique to a company's operational processes.
- **OJT provides a safe environment to make mistakes.** One of the necessary features of any training is that it allows employees to practice in a climate of safety. New hires initially can be trained with equipment, operations, and environments not engaged in the actual production or delivery of services. Once a level of competency is achieved with various job tasks, they gradually can be introduced to functions associated with the company's actual operation.

[6] Adopted from Training Magazine March 26, 2021, *The Value of On The Job Training*, Thomas Montgomery

On-the-job training does require an investment by your organization. For example, trainers may need to be removed from specific critical business functions to instruct and mentor new employees, and equipment dedicated to business operations may need to be re-tasked for training activities. In addition, investment costs such as trainers' and trainees' wages may be lost if the trainee resigns or is terminated. Trainees who progress slower than other employees also may result in added investment. These disadvantages likewise can be ascribed to other methods of training, but comparatively the investment that OJT offers is more cost-effective than other training techniques.

Success Factors

Selecting a trainer is an important step in the success of any OJT program. Traditionally, training falls under the supervisor's responsibilities, but unless the supervisor possesses the necessary skills and qualities, your OJT program may be destined to fail. In fact, some people simply do not have the patience, competence, or desire to train others. Consequently, selecting someone who possesses the character and communications skills to train is crucial.

Trainers should exemplify the company's values and be perceived as a role model or someone who can be trusted. They should possess a thorough knowledge of the company's systems and processes, but they also should be familiar with the company's goals, culture, and organizational climate. It is important, therefore, that trainers exhibit behavior and conduct you expect from your workforce. For example, grumbling, gossiping, and political games introduce dysfunction into your business and can proliferate through the actions of the trainer and other employees. Consequently, they should demonstrate the strength of conviction to determine the suitability of the trainee for employment. Wasting time and money on the wrong employee jeopardizes their safety and affects company moral and the productivity of the business operation.

Regardless of whether your trainer is a supervisor or another employee, they should be trained on how to instruct others. Some trainers have a natural ability to train, but it is still beneficial to enroll them in some form of "train-the-trainer" program. There are psychological processes associated with adult learning that facilitate the acquisition of information and skills development. Things such as reinforcement, cognition, and other learning principles should be understood to maximize your OJT investment.

Key Considerations

The comprehensive nature of OJT enables even the smallest company to maximize the benefits of training. It can be rapidly designed using the company's resources and is flexible and cost-effective. Key considerations, however, are the quality of the training and the effectiveness of the trainer(s). Designing a structured OJT program with specific goals, along with the careful selection of trainers, are essential steps in ensuring a successful in-house OJT program.