U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

901 Locust Street, Suite 480
Kansas City, MO 64106

NOTICE OF AMENDMENT

VIA ELECTRONIC MAIL TO: **mark.hewett@nngco.com**, **thomas.correll@nngco.com**; **john.gormley@nngco.com**

July 12, 2024

Mr. Mark Hewett
President and CEO
Northern Natural Gas Company
1111 S. 103rd Street
Omaha, NE 68124

CPF 3-2024-027-NOA

Dear Mr. Hewett:

From September 8 through September 11, and September 23 through September 25, 2020, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code (U.S.C.), inspected procedures for the Northern Natural Gas Company (NNG) Control Room located in Omaha, Nebraska. NNG updated its Control Room Management procedures initially as a result of this inspection in 2020 and continued to work on procedure amendments with PHMSA during meetings held at various times including those occurring in September 2022 and August 2023.

As a result of the inspection and NNG's continued work on procedure amendments, PHMSA has identified apparent inadequacy found within NNG's plans or procedures. The items inspected and the inadequacies identified are described below:

1. § 192.631 Control room management.

(a) General.
(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .
(b) Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating

> **conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:**
> **(1) . . . .**
> **(4) A method of recording controller shift-changes and any hand-over of responsibility between controllers;**

NNG's procedures 50.200, entitled "Controller Roles and Responsibilities" (Procedure 50.200), and 50.201, entitled "Providing Adequate Information – Shift Exchange" (Procedure 50.201), were not adequate to address any hand-over responsibility between controllers as required by § 192.631(b)(4). Specifically, while the procedures did require that a controller log-on to the console when handing over responsibility to another controller, nothing required that the controller leaving the console would log-off, or clarified that the SCADA system would automatically log-off the outgoing controller after a period of time, leaving the prior controller's area of responsibility active.

The control room has multiple consoles (North Horsepower, North Town Border Station (TBS), and South/Central), all three of which can monitor and control any other console's information. The control room procedures and SCADA system allow multiple controllers to be logged onto the SCADA system at any given time. Some individuals that are not qualified controllers also have access to the control room, such as the control room Director. Additionally, during certain times, controllers have completed training on only one or more consoles but have not completed training relevant to all of the specific consoles with the assigned area of responsibility. Procedure 50.100, entitled "Control Room Management," required a controller to be qualified, and Procedure 50.200 required a log-on, but nothing required a controller to perform a log-off function. Since multiple controllers can be logged-on at the same time, and this log-on feature sets their area of responsibility based on qualifications and supervisor's assignment for the specific day or night, nothing would prevent unqualified individuals from operating a console, unless a log-off function is required.

NNG's Procedure 50.200 in section 3.2.2 stated "[a] monthly audit will be completed to verify a controller did not operate on a console they were not qualified for. Document any violations in a deviation report." However, if controllers that are qualified can stay logged on indefinitely, then anyone in the control room (qualified or not) could access the console and execute commands or acknowledge alarms without this being detected or discovered in the monthly audit function. Additionally, if controllers are not required to log-out/log-off or if the SCADA system does not automatically log-out/log-off qualified individuals within a certain time frame, individuals that had not completed cross-training on all consoles would also be able to execute commands and respond to information for systems they were not qualified for. By not requiring a log-off function, the monthly audit would not be able to determine if a console had a person operating it that was not qualified for that area of responsibility.

NNG's procedures 50.200 and 50.201 require amendment to adequately address the hand-over responsibility between controllers and to adequately establish and implement the monthly review process regarding qualified controllers as described in Procedure 50.201, section 3.2.2.

2. § 192.631 Control room management.

(a) General.

(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section . . . .

(b) . . . .

(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see §192.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

NNG's procedure 50.202, entitled "Providing Adequate Information-SCADA Upgrade" (Procedure 50.202), was not adequate for defining adding, expanding or replacing a SCADA system as required by § 192.631(c)(1). Specifically, API RP 1165, section 3 Definitions, at 3.25 states that a SCADA system is, "[a] system which is a combination of computer hardware and software used to send commands and acquire data for the purpose of monitoring and controlling.is comprised of hardware and software." As a result, hardware individually, software individually, or both hardware and software can be changed in an addition, expansion, or replacement of the SCADA system. The entire SCADA system is not required to be changed for a SCADA system expansion or addition, or replacement to occur. Procedure 50.202 did not clearly identify the types of hardware that when added, expanded or replaced (such as servers, communications components, or consoles) will result in API RP 1165 implementation.

Additionally, the requirements of API RP 1165 are not just applicable to a SCADA system that is upgraded. Other statements within NNG's procedure were not clear regarding meaning as well, such as the following:

> 3.6 Northern considers an expansion of the SCADA system as the addition of a real-time/historical environment integrated into the current SCADA systems. Current SCADA systems include the primary, backup and model office/test systems.

This statement should be clarified as to whether or not it means a software or a hardware change as well. Further, neither the procedure nor the engineering standard for the HMI referenced in the procedure (NNG's procedure, entitled "ES 5675 General Specifications for HMI") provided clarity on what record would be used to demonstrate compliance with the implementation of API RP 1165 sections 1, 4, 8, 9, 11.1, and 11.3, per § 192.631(j)(1).

Procedure 50.202 requires amendment to adequately address the types of individual hardware or individual software changes that will result in implementation of the appropriate sections of API

RP 1165. Additionally, the record that will be used to demonstrate API RP 1165 has been implemented needs to be added to the procedures.

3. § 192.631 Control room management.

> **(a) General.**
> **(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section . . . .**
> **(b) . . . .**
> **(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:**
> **(1) . . . .**
> **(2) Conduct point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;**

NNG's procedure 50.203, entitled "Providing Adequate Information – SCADA Point to Point Verification" (Procedure 50.203), and ES-0165 entitled "Turnover/Start-Up Procedure for New Construction " (ES-0165), along with various engineering commissioning checklists, were not adequate to define point-to-point verifications between SCADA displays and related field equipment when field equipment is added or removed and when other changes that affect pipeline safety are made to field equipment or SCADA displays as required by § 192.631(c)(2). Specifically, Procedure 50.203 stated in section 3.1:

> For the purposes of this procedure, Northern considers adding or moving field equipment (including but not limited to compression station equipment, meters, transmitters and valves) to be defined as a change that affects the data communication to the SCADA system from monitoring devices such as a remote terminal unit (RTU) or programmable logic controller (PLC). This is further defined as a field equipment change that results in an addition or change in RTU or PLC address for a safety related alarm point. This type of change would require the SCADA support team and field representative to perform a point-to-point verification between the SCADA system and the field end device in order to ensure gas controllers are viewing correct data.

NNG's Procedure 50.203 was not clear that either a change in data communication to SCADA, or, separately, a change or addition to an address would result in a point to point being conducted. This requires amendment because while a change in a transmitter range could result in a loss of communication during the replacement depending on how this was performed in the field, the addressing may remain the same, but the range of the device would change, and it is not clear if data communication such as loss of communication is considered. Data communication may only mean a change in address or method of communication, and this would not adequately ensure gas controllers are viewing correct data. Clarification to procedures should include requiring flow computer changes to result in point-to-point verifications as well.

Further, NGG's inadequate point-to-point verification procedures impacted alarm management procedures, required under § 192.631(e)(1). Procedure 50.203, section 5.1.2, stated, "[c]alculated points set up for processing alarms will be validated when points are added or deleted. Communication from the new point will be cycled from on to off and verify the loss of communication changes the calculated points color." However, it would be possible for a point involved in a calculation to have the same point with the same address used but the range changed, and that range change could impact the calculation. This would only work correctly if the calculated point did not have any separate alarm setpoints. For example, this would not be accurate for a calculated point such as that for a pack alarm as defined in the Alarm Management plan referenced as 50-400.

Additionally, Procedure 50.203 section 5.1.15 stated:

> For project related SCADA display changes, a field technician or engineering representative will submit a SCADA screen change EATS ticket and installation report documenting SCADA point requirements for the screen prior to the work being performed. The EATS ticket will be approved by a designated representative from gas control. For non-project related SCADA display changes, a designated representative from gas control will submit a SCADA screen change EATS ticket to the SCADA support team. The display and point-to-point validation will be conducted per 5.1.14.

However, nothing required that these changes be made before the project related assets are pushed to the controllers or become operational and this would clearly be required for the controllers to have the necessary information and tools to complete their roles and responsibilities.

Also, it was not clear how other aspects of point-to-point will be conducted and when. From Procedure 50.203, nothing was specially described regarding logic testing. Logic testing would be required for ESD applications, or elements such as valve status alarming on emergency valves. An alarm condition would be detected and alarmed on when the valve did not complete the command sequence within a certain amount of time. While Procedure 50.203 did reference the following ES 0165 procedures and the associated commissioning checklists,

> ES 0165 - Turnover/Start-Up Procedure for New Construction;
> ES 0165e - Appendix E: Fire and Gas System Commissioning Checklist;
> ES 0165k - Appendix K: SCADA Commissioning Checklist; and
> ES 0165v - Appendix V: ESD Commissioning Checklist;

it was not clear whether this is only achieved by testing with air. Air testing would not be sufficient in some cases to confirm adequate information is available for controllers, as timing and operation can be impacted when the commodity is added to the pipe, thus impacting the timing of adequate alarming. It was also not clear from procedures how the deficiencies identified during the commissioning (known as COMM list) are addressed before the controller is required to operate the system. This is noted as in ES 0165k, as it stated in the Instructions section, "[i]f a station was partially validated, provide a list of points that were left in the "COMM" group to DL-Gas Control." The COMM list or group should not have any elements that could impact safety implemented for the controller before completely tested and this is not clear in procedures.

Section 192.631(e)(1) requires accurate alarms and is not time dependent so this would apply any time commodity is in the pipeline (regardless of flowing or not) and would impact point-to-point activities.

Finally, neither Procedure 50.203 nor the procedures referenced in ES-0165 defined how loss of communication is checked on point types beyond that of Calculated Points. Loss of communication is an alarm that must be checked to operate correctly through a point-to-point prior to operation. The procedures did not define how valve status alarms, various aspects of power including UPS systems, or man down alarms would receive a point-to-point as required. Procedures were not clear on how simulation would be noted in the point-to-point documentation and that the location of the simulation would be identified, as this can impact whether or not the controller has sufficient information to complete their roles and responsibilities upon point-to-point completion.

Procedures 50.203 and ES-0165 with associated commissioning checklists require amendment to sufficiently clarify these elements identified and to sufficiently address the requirements of § 192.631(c)(2) and § 192.631(e)(1). Further these procedures need to clarify points that can impact safety as required by § 192.631(c)(2).

4. § 192.631 Control room management.

> **(a) General.**
> **(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .**
> **(b) . . . .**
> **(e) *Alarm management.* Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:**
> **(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;**

NNG's Procedure 50.400, entitled "Alarm Management," was not adequate as it did not clearly define how a review is conducted on alarms to ensure accuracy and the support of safe pipeline operations as required by §§ 192.631(e) and 192.631(e)(1). Specially, Section 192.631(e) requires the Alarm Management plan to provide for effective controller response to alarms, and must include provisions to review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations. Yet the Procedure 50.400 was not clear as to which points will be reviewed to ensure accuracy and that the alarms are set to support safe pipeline operations.

LoLo pressure alarms were identified as a Critical Alarm A priority 2 in Appendix A and not as a Safety Related Alarm Priority 1. It was not clear in procedures if this priority of alarm would be reviewed to ensure accuracy and the support of safe pipeline operations.

Similarly, Appendix A identified an alarm priority called Safety-Related Priority 1. However, not all alarms that support safe-pipeline operations were found in this priority. For example, Priority 8 was communication failure. Communication failure is an alarm state that is necessary to support safe operations. Additionally, valve alarms associated with incorrect commanded status or a valve that has not achieved a commanded state within a certain amount of time were not identified in Appendix A. Only ESD valves are identified as Safety-Related Priority 1. The priority and alarm function associated with other valves was unknown. Yet valves were defined as a point that is Safety-Related in section 3.1.8 of Procedure 50.400. The procedure needs to clarify if all points that are safety related, regardless of Alarm Priority, will be reviewed to ensure the setpoints or values are accurate and support safe operation.

Also, Appendix A indicated H2S Delivery pressure would have a priority of 1 called Safety-Related Alarm, but other information indicated that H2S high limit in composition would be a Safety Related Alarm Priority 1 with delivery pressure treated difference as a Critical Alarm A Priority 2. Because the Safety-Related alarm priority was not the only priority group that must be accurate and established to support safe operations, it was not clear from Procedure 50.400 how these types of alarms in Priority 2 would be reviewed.

The operator identified verbally during the inspection and confirmed this information during follow-up meetings as late as August 2023 that rate-of-change (ROC) alarms exist on certain points. However, ROC alarms were not described in the Procedure 50.400 nor listed on the Appendix A: Alarm and Alert priorities table. As a result, it was not clear if these alarms would be reviewed to support safe pipeline operations or what priority would be relevant.

Finally, Procedure 50.400 defined "Safety-Related Point" in section 3.1.8 as an "input or output point on the system that when it exceeds allowable levels results in a safety-related alarm or has the potential to develop into abnormal operations or a safety-related condition. Input points include pipeline and station inlet and outlet pressures, pressure regulating inlet and outlet pressures, delivery pressures, calculated line pack values, flow rates, valve operation, fire detection, gas detection, H2S detection, smoke detection, temperatures associated with the gas cooling and high filter separator levels. Output points include set points for pressure and turbine speed control, command for valve control, station isolation and unit shutdowns." However, not all of these types of points were clarified as having a priority on Appendix A, such as flow rate or pack. If this is because alarms are not set on these two types of inputs or as an output, this should be clarified in the Alarm Management procedure 50.400 as it was not clear why these were not listed in Appendix A.

Procedure 50.400 and Appendix A require amendment to clearly define how and on what specific points (including the various priorities) a review is conducted on alarms to ensure accuracy and the support of safe pipeline operations as required by §§ 192.631(e) and 192.631(e)(1).

5. § 192.631 Control room management.

> **(a) General.**
> **(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .**
> **(b) . . . .**
> **(e) *Alarm management.* Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:**
> **(1) . . . .**
> **(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;**

NNG's Procedure 50.400 entitled "Alarm Management," was not adequate as it did not clearly describe how the identification at least once each calendar month will be accomplished for points that affect safety that have been taken off scan in the SCADA host, had alarms inhibited, generated false alarms or that have forced or manual values for period of time exceeding that required for associated maintenance or operator activities as required by §§ 192.631(e) and 192.631(e)(2). Specifically, section 5.4 of Procedure 50.400 stated:

5.4 Reports and analysis will be conducted on a monthly or annual basis as defined below to demonstrate compliance and measure effectiveness.

- 5.4.1 An alarm/alert review process will be completed at least once each calendar month. This review will consist of the following:
    - 5.4.1.1 Review the number of Safety-Related Alarms that have occurred, been suppressed, manually overridden, points taken off-scan, shown to be false or had alarm limits changed and include in the monthly report.
        - 5.4.1.1.1 Gas controllers shall include actions taken on all Safety-Related alarms received in the daily log.
        - 5.4.1.1.2 Sequential alarms received during the day due to maintenance activities can be consolidated in one daily log entry.
    - 5.4.1.2 Review the number of Alarms/Alerts that have occurred, been suppressed, manually overridden, points taken and off-scan to identify excessive reoccurrences and include in the monthly report.
        - 5.4.1.2.1 The top 10 alarms and alerts from each console will be reviewed monthly to determine the source of the alarm and if limits require

adjustment.

- 5.4.1.3 Review points with frozen data from RTUs, PLCs or SCADA that are not caused by loss of communications.
- 5.4.1.4 Review RTU communication outages and document the duration and actions to resolve the outage.
- 5.4.1.5 Parked alarms and alerts will be reviewed on a continuous basis and addressed as appropriate.
- 5.4.1.6 The manager of gas control or designee shall document and track deficiencies in EATS and follow up with proper departments to ensure excessive, nuisance, false, parked, suppressed and manually overridden indications are addressed in a prompt manner.

Section 195.446(e) requires the operator to have an alarm management plan that will provide for effective controller response to alarms. As such, controllers are only a part of the Alarm Management process that will identify what must be reviewed for points that can impact safety each month as required by 195.446(e)(2) and have deficiencies addressed as required by 195.446(e)(6). The following is not clear from procedures:

1. How the review of calculated points and associated alarming if the point can impact safety will be included on a monthly basis (such as total flow through a station).
2. How frozen data (or forced data) at the Remote Terminal Unit (RTU), Programmable Logic Controller (PLC) or in SCADA will be detected and reported on is not clear. Controllers are not the only individuals that this could be reported by. For example, field technicians or SCADA personnel could identify forced data on points that can impact safety, or automatic programming can identify this information, but it is not clear in procedures what is being done.
3. How standing alarms and alerts will be reported on and identified each month when associated with points that can impact safety was not clear in procedures. While this is described as a continuous review process, if it is associated with a point that can impact safety, it would be a point when in alarm is required to be part of the monthly review and would require addressing.
4. How points taken off-scan will be identified or reported on. Again, this should not fall only to the controllers to identify, as SCADA personnel can impact this change and this may not be evident to the controller.
5. How the alarm inhibit function will be detected and reported on each month. While controllers can report on certain aspects of this function, others may also perform this task, such as SCADA, and this must be identified as well. Suppression may be in place at the time of the monthly report, and this would not be clearly identified without a reporting function being established.
6. How false alarms will be determined was not clear in procedures. While false alarms may include chattering or nuisance alarms as described in Procedure 50.500, section 5.4.1.2, it is not the only potential source for false alarms. Section 3.1.5 defined a false alarm. However, it was not clear if controllers receive an alarm from the field due to maintenance activities, but they were not notified in advance of this activity, if

this would result in a false alarm and if so, how this would be included in the monthly review and addressed as required by section 5.4.1.6.

7. The process as described in Procedure 50.400 did not include points that can impact safety that have been in manual for periods of time exceeding that required for associated maintenance or operating activities. This would include if remote/manual, hand/off/auto, or remote/local switching can occur in the field on a valve or compressor such that, if the remote function is removed from the controller (placed in manual, local, hand, etc.) for periods exceeding associated maintenance or operating activity requirements as part of the monthly report, and address the identified deficiencies.
8. How loss of communication will be determined and reported on.
9. The process as described in Procedure 50.400 and did not include what specific reports or data sources will be reviewed as part of the monthly review process, such as emails being provided when alarm setpoints or limits are moved, alarm/event logs, RTU communication reports, or daily logs. It also did not clarify what information will be used as the record to demonstrate this has been sufficiently accomplished each month.

Procedure 50.400 requires amendments to clarify how the reviews identified in 5.4.1 will be accomplished, what data sources will be used as inputs for the monthly review process (emails, specific reports, controller shift logs, alarm/events logs, etc.), and how the output will be recorded (EATS and Summary files, etc.) to complete the monthly review required by § 192.631(e)(2). Additionally, the amendments need to address how aspects of points taken off-scan, forced data, alarms inhibited, false alarms, and manual conditions on points affecting safety will be identified monthly.

6. § 192.631 Control room management.

(a) General.
(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .
(b) . . . .
(e) ***Alarm management.*** **Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:**
(1) . . . .
(3) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;

NNG's Procedure 50.400 did not adequately define the process used to verify the correct safety-related alarm set-point values and alarm descriptors at least once each calendar year, but at intervals not to exceed 15 months as required by § 192.631(e)(3).

Specifically, Procedure 50.400 section 5.4.2 stated:

- 5.4.2 An alarm/alert review process will be completed annually, but at intervals not to exceed 15 months.
  - 5.4.2.1 The review process will consist of verifying the correct Safety-Related Alarm set point values and descriptions. Additionally, the alarm management procedure will be reviewed as part of this process to determine effectiveness.
  - 5.4.2.2 The annual review process will include an analysis of safety-related points to ensure continued applicability.
  - 5.4.2.3 The annual review process will utilize the Annual Safety-Related Alarm report and Annual Alarm Management Plan Review Report.
  - 5.4.2.4 Remedies to improve alarm or alerts include:
    - Optimizing set points
    - Addressing chattering or flooding alarm/alerts
    - Evaluating priority levels for alarms/alerts
    - Determining if an alert should be moved to an alarm
    - Determining if an alarm should be moved to an alert
  - 5.4.2.5 The manager of gas control or designee shall follow up with proper departments to ensure deficiencies are addressed in a prompt manner.

During the inspection, NNG verbally explained that the process involved creating a list of the alarm setpoint values and alarm descriptors per location by the control room with SCADA assistance. This information was then sent to the various field locations for field personnel to sign off on the correct alarm setpoint values per point and the alarm descriptors. However, none of this was described as part of the process in Procedure 50.400, nor were the reports noted in section 5.4.2.3 included as part of NNG's Alarm Management procedure. It was not clear that either one or both reports identified in section 5.4.2.3 were developed using the existing SCADA system data or a Master Alarm Database separate from the SCADA system. It was also not clear how changes that have been processed through EATS or as part of other MOC processes would be confirmed to still be in place for relevant temporary or permanent changes. How verification of alarm setpoint values and alarm descriptors is performed was not adequately defined in Procedure 50.400.

Procedure 50.400 requires amendment to describe how the requirements of § 192.631(e)(3) will be implemented.

7. § 192.631 Control room management.

(a) General.
(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .
(b) . . . .

> **(e)** ***Alarm management.*** **Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:**
> **(1) . . . .**
> **(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months that will assure controllers have sufficient time to analyze and react to incoming alarms;**

NNG's Procedure 50.400 was not adequate to assure that controllers have sufficient time to analyze and react to incoming alarms as required by § 192.631(e)(5). Specifically, Procedure 50.400 section 5.5.2 stated that during the review process the data collected will be analyzed to determine if the volume of activity processed by the gas controller is at a level that does not jeopardize the safe operation of NNG facilities. Section 5.5.2.2 stated that NNG will measure the controller's workload against internally defined Key Performance Indicators (KPIs) to ensure the controller performance is adequate. However, which specific KPIs will be used has not been defined. KPIs need to be defined before the analysis is able to be completed and documented. This is significant to Procedure 50.400 being developed correctly as designed and then implemented. Also, Procedure 50.400 did not clearly state where KPIs would be recorded and how these selected KPIs would be used to determine the volume of activity was at a level not to jeopardize the safe operation of NNG facilities.

Additionally, review of controller workload is required to determine that the controller has sufficient time to analyze and react to incoming alarms. While KPIs are certainly part of that answer when selected correctly, without reviewing the time required for controllers to acknowledge alarms and respond based on priority, the process to confirm controllers have sufficient time to analyze and react to incoming alarms is incomplete. NNG's alarm rationalization process may need to be adjusted and redone if the designed and expected time of response by priority cannot be achieved by controllers. Adjusting and redoing the alarm rationalization process was not clearly required in NNG's procedures.

Finally, how deficiencies associated with this workload analysis will be addressed and recorded is not adequate as defined in Procedure 50.400 section 5.5.2.1. Section 5.5.2.1 explained:

> If the analysis reveals deficiencies, the gas control manager will take steps necessary to ensure safe operation of facilities by:
>
> - Reducing the volume of phone calls
> - Reviewing changes that have been made to the overall operations
> - Exploring and implementing automated recordkeeping processes
> - Reviewing the need and applicability of alerts
> - Requesting staffing additions
> - Requesting controller input
> - Other actions as identified.

However, it is not clear that "other actions as identified" would include actions such as console additions, console asset reassignment, or a change to the alarm rationalization process. These three actions are also types of changes that impact the time for controllers to respond to alarms. NNG's procedures need amendment to clarify that these three actions are also possible outcomes of a workload study.

Procedure 50.400 requires amendment to clarify how NNG will determine that that the volume of alarms does not jeopardize the safe operation of NNG facilities, to identify the specific KPIs that will be used, and to clarify that other actions as identified would include at least console additions, console asset reassignment, and changes to the alarm rationalization process.

8. § 192.631 Control room management.

> **(a) General.**
> **(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section….**
> **(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by §§192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.**
> **(b) . . . .**
> **(f) Change management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:**
> **(1) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;**
> **(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and**
> **(3) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.**

NNG's operating procedures 50.500, entitled "Control Room Change Management" (Procedure 50.500), and 10.310, entitled "Management of Change" (Procedure 10.310), were not adequate to establish communications between the control room representatives, operator's management and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration as required by § 192.631(f), including §§ 192.631(f)(1), 192.631(f)(2), and 192.631 (f)(3). Additionally, procedures relevant to § 192.631(f) were not properly integrated, as required by § 192.631(a)(2), and did not identify the records to demonstrate compliance as required by § 192.631(j)(1). Specifically, Procedure 50.500 did not reference Procedure 10.310, when cross reference is clearly necessary. Procedure 50.500 is used for certain types of changes, permanent and temporary, that affect the control room. Procedure 10.310 was used when projects are being planned and physical changes implemented including changes to equipment or configurations or significant pipeline hydraulic or configuration changes that would also impact the control room. Both of these procedures impact change that could affect control room operations and require coordination with control room personnel.

Further Procedure 50.500 did not clarify how changes from the implementation of Procedure 10.310 would only result in one or more of the three following plans: a Gas Management Plan (GMP), a Facility Operating Plan (FOP), or a Configuration Plan. Similarly, while the Enterprise Action Tracking System (EATS) was referenced in both Procedure10.310 and Procedure 50.500, it was not clear what types of changes created by Procedure 10.310 would be sent in EATS for control room required notification. Procedure 10.310 also did not include specifics around notification to the control room or to control room management or reference Procedure 50.500.

Procedure 10.310 in section 1, entitled “Purpose,” explained that the procedure includes the identification and consideration of permanent or temporary, technical, physical procedural and/or organizational changes that impact pipeline integrity, liquid natural gas (LNG) facilities, and underground storage facilities including high consequence areas (HCAs) and the effect these changes might have. The procedure also included the basic criteria outlined in ASME/ANSI B31.8S Section 11 and fulfills the requirements § 192.911(k) and API RP 1173, Pipeline Safety Management Systems, Section 8.3. However, the Procedure 10.310 did not reference the Control Room requirements set forth in §§ 192.631(f)(1), (2), or (3) and was not appropriately integrated with the control room requirements as required by § 192.631(a)(2). This is significant because many of the requirements in this procedure regarding permanent or temporary changes could impact the control room and have not appropriately been considered for integration, communication and coordination, or for required control room notification when making changes that affect the control room as required.

Additionally, Procedure 50.500 section 5.9 requires modification as it did not clearly state how the representative from facility planning will be communicating and coordinating with the control room as required. NNG’s Procedure 50.500 section 5.9 stated:

> Gas control or facility planning personnel shall participate in planning meetings for construction projects that have the potential to cause significant system hydraulic changes or require a configuration change. The meetings shall take place well in advance of the proposed hydraulic or configuration change to ensure control room or facility planning personnel provide input, understand and are prepared to act on the proposed changes. Participation in the meetings shall be documented in any of the following documents:
>
> - Level A or Level B estimate review process
> - Stakeholder meeting notes detailed in Asite
> - Communications through the Outage Tracker

- Review and approval through the GMP process
- Email communications for the System Operation Weekly Overview meeting.

The requirements of §§ 192.631(f)(1), (2), and (3) are specific to the control room or control room management and the requirement of facility planning alone, as described in section 5.9, did not meet the requirements of these subsections. Additional description is needed to establish how the representative from facility planning will be communicating and coordinating with the control room.

Additionally, based on the items identified in Procedure 50.500 section 5.9, section 6.0, which discussed NNG's record keeping, would be required to also include all of these aspects such as Asite, and Outage Tracker and email communications. The list of maintained records in section 6.0 did not include any of the documents to be created to record the planning meetings required in section 5.9, nor did it include all of the elements identified in Section 5.9 but these would be required records for demonstrating compliance with §§ 192.631(f) and (j)(1).

Procedure 50.500 requires clarification in Section 5.10 and 5.11 regarding how the communication will occur and what record of that communication would demonstrate compliance. Procedure 50.500 section 5.10 explained, "IT emergencies are coordinated through the IT EMRT team. The SCADA manager is a member of the IT EMRT team and will contact the OCC when emergency conditions exist that have potential to affect the SCADA system and gas control operations. The OCC representative will contact gas control." Section 5.11 explained, "[t]he SCADA manager or SCADA IT personnel will contact the OCC when emergency conditions exist that have potential to affect the SCADA system and gas control operations. The OCC representative will contact gas control." Neither section 5.10 nor 5.11 clearly identified how this communication and contact with gas control will occur (verbally, email, etc.) and what record(s) will be used to demonstrate compliance (shift log, email, etc.). These sections require amendment to know how this communication and contact will occur and what records will be used to demonstrate compliance.

Finally, Procedure 50.500 requires amendment to correct a reference used in Section 5.12. Section 5.12 stated, "[c]hanges to the SCADA system will be communicated with gas control personnel through processes established in operating procedure 50.220 Providing Adequate Information - SCADA Upgrade." The "operating procedure 50.220" did not exist. However, a Procedure 50.202, entitled "Providing Adequate Information - SCADA Upgrade," did exist, so the reference 50.220 needs corrected to 50.202.

NNG's operating Procedures 50.500 and 10.310 require amendments to sufficiently address the requirements of §§ 192.631(f)(1), (f)(2) or (f)(3) and to be properly integrated, as required by § 192.631(a)(2), in order to correct references and clarify records to demonstrate compliance as required by § 192.631(j)(1).

9. § 192.631 Control room management.

(a) General.

> **(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .**
> **(b) . . . .**
> **(g) Operating experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:**
> **(1) Review incidents that must be reported pursuant to 49 CFR part 191 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:**
> **(i) Controller fatigue;**
> **(ii) Field equipment;**
> **(iii) The operation of any relief device;**
> **(iv) Procedures;**
> **(v) SCADA system configuration; and**
> **(vi) SCADA system performance.**

NNG's Procedure 50.600, entitled "Control Room Management Operating Experience –Review of Reportable Incidents," was not adequate to meet the requirements of §§ 192.631(g)(1) and (j)(1). Specifically, Procedure 50.600 section 5.1 did not describe what NNG will review to determine whether or not the control room actions contributed to the reportable event, section 5.2 failed to address adequately contributory control room actions, and section 5.3 incorrectly describes when a review is necessary.

Procedure 50.600 section 5.1 stated:

> If a regulatory agency reportable incident occurs, an OCC call will be completed to ensure appropriate stakeholders are informed. Gas control management will immediately complete an investigation to determine if controller or control room actions caused or may have contributed to the event. The vice president of gas control or designee(s) will utilize Form 50.600a Control Room Management Reportable Incident Review Form to conduct and document the investigation. Results of the investigation will be immediately reported to the incident commander, human resources and the legal department to determine if there is a requirement for drug and alcohol testing as stated in operating procedure 10.103 Investigation of Accidents & Failures.

However, Form 50.600a only referenced the required information on the 30-day written report (PHMSA Form 7100.2) which is provided by the operator. This is significant because in both PHMSA Form 7100.2 and NNG's Form 50.600a there is an option to select the answer "No, the operator did not find that an investigation of the controller(s) actions or control room issues was necessary…" NNG's procedures indicated that if this option was selected, that a review of whether or not the control room operations contributed to the event was not required. Regardless of the content of PHMSA Form 7100.2, the review of a reportable incident is required by §

192.631(g)(1) to determine if the control room actions contributed to the event. How this review will be conducted and what documentation will be reviewed was not sufficiently identified in procedures. Additionally, what records would be kept in order to demonstrate this review was performed is not defined as required by § 192.631(j)(1).

Additionally, Procedure 50.600 section 5.2 stated:

> If it is determined that the cause of a reportable incident was attributed to one or more of the following, deficiencies shall be corrected, and a lesson learned review will be conducted. Lessons learned from the review will be incorporated, as appropriate, into control room management procedures and the control room management training program, to prevent recurrence.
>
> 5.2.1. Controller fatigue
> 5.2.2. Operator error or misdiagnosis
> 5.2.3. Field equipment failure (impacting control room operations)
> 5.2.4. Control room management procedures
> 5.2.5. SCADA system configuration
> 5.2.6. SCADA system performance.

However, section 5.2 misstated the requirements of § 192.631(g)(1); the control room contribution must be reviewed even if the control room was not the cause of the reportable incident.

Further, § 192.631(g)(1) requires that for a reportable incident, a review to determine whether control room actions contributed to the event must be completed, and if the operator determines that control room activities did contribute to the event, the operator must correct, where necessary, deficiencies related to controller fatigue; field equipment; the operation of any relief device; procedures; SCADA system configuration; and SCADA system performance. However, NNG's procedures included "[o]perator error or misdiagnosis" in place of operation of any relief device, and placed the clarification on field equipment failure around "impacting the control room operations." Thus, Procedure 50.600 misstated the requirements of § 192.631(g)(1).

Also, Procedure 50.600 section 5.3 stated, "[i]f an incident occurs that requires a Pipeline and Hazardous Materials Safety Administration Form 7100.2 (Rev. 01-2010) Incident Report – Gas Transmission and Gathering Systems to be completed and submitted and any items of Part E, Additional Operating Information – numbers 6, 7 or 8 are attributed to the incident, then this operating experience procedure review shall be performed. All lessons learned documentation shall be maintained as a training record." However, Procedure 50.600 should be implemented regardless of NNG's answers to number 6, 7 or 8 on PHMSA Form 7100.2.

Procedure 50.600 requires amendment to clarify how NNG's review will be conducted to determine if control room actions contributed to the event and what records outside of PHMSA Form 7100.2 will be kept in order to demonstrate that review did occur, regardless of answers to 6, 7 or 8 on the PHMSA Form 7100.2. Also, the procedure requires amendment to clarify and meet the requirements of § 192.631(g)(1) for the identified condition specifics and the correction of deficiencies.

10. § 192.631 Control room management.

(a) General.

(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section . . . .

(b) . . . .

(h) Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator . . . .

NNG's procedures 50.700, entitled "Control Room Management Training" (Procedure 50.700), and LMS Training NNGGC00004 Module were not adequate to provide for training each controller to carry out the roles and responsibilities defined by the operator as required by §§ 192.631(h) and 192.631(b). Specifically, Procedure 50.700 and LMS Training Module did not address the training required for the controller regarding 50.205 SCADA Back up Test procedure. Procedure 50.200 did reference Procedure 50.301, entitled "Control Room Evacuation," Procedure 50.204, entitled "Internal Communication Plan Testing for Manual Operations," and Procedure 50.205, entitled "SCADA Back up Test Procedure." However, Procedure 50.700 only referenced the Internal Communication Plan Testing for Manual operations and did not mention or describe training relevant to the Procedure 50.205.

Additionally, the LMS Training Module did address evacuations, but did not clearly include or identify procedures for moving to the backup control room location and did not detail how to use Procedure 50.205 or when to implement Procedure 50.204 from the backup location.

Further, while on-the-job training (OJT) was referenced in Procedure 50.700 regarding the lead controller, nothing was referenced for other controllers. While it was clear from the NNG Gas Control Training Program Outline that OJT will be held for all controllers, NNG's records were not specific for these OJT topics and records would need to be console specific. Procedure 50.700 did not adequately define which records would demonstrate OJT activities covering normal, abnormal and emergencies. Procedures were not clear on how Rate of Change (ROC) alarms or pack values would be used to determine a leak for different pipeline systems associated with each console, and records were not clear as to how or when this was addressed in training.

Procedure 50.202, entitled "Providing Adequate Information - SCADA Upgrade," section 3.8 stated, "[t]he current SCADA system displays have color indicators without associated alphanumeric indicators. Gas controller color recognition will be incorporated and considered during the onboarding process and periodically thereafter." However, Procedure 50.202 did not cross-reference Procedure 50.700, which did mention onboarding and would be specific to a controller’s knowledge, skills and abilities, including confirming how the controller’s ability to detect colors used in the SCADA system would be demonstrated. How the requirements of Procedure 50.202 section 3.8 would be specifically addressed during training was not defined in Procedure 50.700.

Additionally, during the inspection, the NNG Gas Control Training Outline (NNG Outline) was presented as part of the training program to the PHMSA inspector. This document was not attached or referenced in Procedure 50.700 but was part of the process used.

Both Procedure 50.700 and LMS Training Module require amendment to sufficiently address the roles and responsibilities of controllers. Amendment would include elements of training required for the controller to operate or transfer to and from the backup SCADA location. Additionally, Procedure 50.700 requires amendment to clarify what records will exist to demonstrate adequate OJT, to include the NNG Gas Control Training Program Outline, and to describe how Procedure 50.202 section 3.8 will be implemented.

11. § 192.631 Control room management.

> **(a) General.**
> **(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section . . . .**
> **(b) . . . .**
> **(h) Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:**
> **(1) . . . .**
> **(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and**

NNG’s Procedure 50.700 was not adequate as it did not require for pipeline operating setups that are periodically, but infrequently, used the opportunity for controllers to review relevant procedures in advance of their application as required by §§ 192.631(h)(5) and 192.631(j)(1). Specifically, 50.700 section 3, entitled “General,” stated, “[t]his procedure addresses the requirements of DOT § 192.631(h), sections (1), (2), (3), (4), and (5) which outlines the requirements to train controllers on responding to abnormal operating conditions, communicating responsibilities during an emergency, working knowledge of the pipeline system, especially during abnormal operating conditions, and training for relevant but infrequently or rarely used system setups in advance of their application.” This is inaccurate as it misstated the requirements of § 192.631(h)(5); “infrequently or rarely used” is not the same as “periodically, but infrequently used.”

Additionally, while Facility Operating Guidelines (FOG) training was referenced in Procedure 50.700, section 5.3, and Configuration plans are referenced in section 5.4, Procedure 50.700 did not take into account procedural movements that the operator knows only occur seasonally or periodically regardless of a FOG or Configuration plan. Examples of such procedural movements are storage applications, facility bypass, or using common or split line operations. During the inspection, NNG confirmed that these types of procedures were not included in the scope of sections 5.3 or 5.4. These types of procedures would be unique per console and these types of procedures had not been addressed in 50.700 or other training documentation. Without the specific identification of these types of procedures, and the training documentation identifying a record that would track the opportunity for the review in advance of their application, the requirements of §§ 192.631(h)(5) and 192.631(j)(1) have not been met.

NNG Procedure 50.700 requires amendment to address pipeline operating setups that are periodically used, and to identify per console the procedures that would be used seasonally, or other procedures not identified in a FOG or Configuration plan that are unique per console.

12. § 192.631 Control room management.

(a) General.
(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .
(b) . . . .
(j) Compliance and deviations. An operator must maintain for review during inspection:
(1) . . . .
(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

NNG’s Procedure 50.100 did not require adequate documentation regarding demonstration of any deviation from NNG’s procedures, required by § 192.631, was necessary for the safe operation of a pipeline facility, as required by § 192.631(j)(2). Records to demonstrate compliance associated with deviations are stored in multiple systems that require and contain very different information. Documentation on deviations was addressed in Procedure 50.100, section 6.1, however Procedure 50.100 did not clearly state: (1) how records of deviation will be identified, (2) if deviation records and the associated procedures will be moved to a common location or reported on from various locations using a specific process for each data set identified in section 6.1 and (3) if any common data that will be collected (such as the name of the procedure relevant to the deviation and when it occurred).

Procedure 50.100 section 6.1 stated:

> Records required to be maintained by Control Room Management regulations, including deviation records, will be identified and stored in the company's record management system. The individual 50 series operating procedures detail what records are required to be maintained. A summary of deviation records will be stored in the company's record management system under 50.100. The record will determine if the deviation was necessary for pipeline safety. Storage of historical records shall be contained in various systems including the Maintenance Control System (MCS), Learning Management System (LMS), Company Records Management system (P8), Enterprise Action Tracking System (EATS) or other company intranet locations.

It is not clear from Procedure 50.100, section 6.1, how deviations beyond that of the 50 Series Procedures, such as a deviation from the SCADA procedure referenced (OP 20.401 Supervisory Control and Data Acquisition Systems), would be recorded and become part of the deviation records associated with Procedure 50.100.

Procedure 50.100 requires amendment to adequately define (1) how NNG will adequately document that any deviation from the procedures as required by this section was necessary for the safe operation of a pipeline facility and how records of deviation will be identified, (2) if deviation records and the associated procedures will be moved to a common location or reported on from various locations using a specific process for each data set identified in section 6.1, and (3) if any common data that will be collected (such as the name of the procedure relevant to the deviation and when it occurred). Additionally, Procedure 50.100 requires amendment to clearly define how other records associated with deviations outside of the 50 Series Procedures, but applicable to this section, would be documented.

<u>Response to this Notice</u>

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.206. Enclosed as part of this Notice is a document entitled Response Options for Pipeline Operators in Enforcement Proceedings.

Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. § 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

Following the receipt of this Notice, you have 30 days to submit written comments, revised procedures, or a request for a hearing under § 190.211. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this

Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue an Order Directing Amendment. If your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.206). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 60 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

It is requested that NNG maintain documentation of the safety improvement costs associated with fulfilling this Notice of Amendment (preparation/revision of plans, procedures) and submit the total to Gregory A. Ochs, Director, Central Region, Pipeline and Hazardous Materials Safety Administration. In correspondence concerning this matter, please refer to **CPF 3-2024-027-NOA** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

KAREN A BUTLER Digitally signed by KAREN A BUTLER
Date: 2024.07.12 16:13:50 -05'00'

Gregory A. Ochs/kab
Director, Central Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

Enclosure: *Response Options for Pipeline Operators in Enforcement Proceedings*

cc: Thomas Correll, Vice President, Safety and Risk, NNG (Thomas.correll@nngco.com)
John Gormley, Sr. Corrosion Specialist, NNG (john.gormley@nngco.com)