2010 Voluntary Protection Programs (VPP) Self-Evaluation Process Safety Management (PSM) Supplement B

Due by February 15, 2011

VPP participants whose operations are covered by the Process Safety Management (PSM) Standard must provide responses to each question that is applicable to their operations. Responses must cover all PSM-related operations. Please indicate that a question is "Not Applicable" if it addresses functionality outside the scope of the operations, <u>and briefly explain why.</u>

Question 1: Does the site have a mechanical integrity (MI) procedure with appropriate inspection protocols for vessels and piping, and what *recognized and generally accepted good engineering practices*(**RAGAGEP) does it utilize?**

Guidance: Example of a RAGAGEP for piping inspection records, include but are not limited to, American Petroleum Institute (API) 570, Section 7.6, API 574, Section 12.1, Center for Chemical Process Safety (CCPS) Guidelines for Mechanical Integrity Systems, Table 9-3, RAGAGEPs for Process Piping, and Table 9-14, Mechanical Integrity Activities for Piping Systems.

Incorporating RAGAGEP into Procedures. Whether an employer can simply incorporate a RAGAGEP the MI program procedure depends on whether the RAGAGEP provides specific instructions/actions or whether the RAGAGEP is generic/vague to the extent that employees required to follow a procedure would be left to interpret the RAGAGEP's requirements absent other instructions from their employer. If the MI program procedure incorporates the RAGAGEP (or a section of a RAGAGEP) as one of its MI program procedures, and that RAGAGEP/MI program procedure provides sufficient specific instructions/ actions, then the RAGAGEP/MI program procedure would be adequate for the employer to safely manage the on-going integrity of the process.

For example, the employer could specify in its written MI program procedure that it is incorporating/ following API 510, Section 6.4 for scheduling on-stream versus internal inspections for pressure vessels with integrally bonded liners. This is acceptable because the instruction or action required by this particular section is specific – "…If the requirements of item b (See item b.5. related to non-integrally bonded liners) above are not met…, the next scheduled inspection shall be an internal inspection."

If the employer's MI procedure for pressure vessel inspection simply incorporates API 510 in its entirety, it would not be satisfactory, because many of the provisions in API 510 are generic and do not adequately provide the specific instructions necessary to manage the MI of the covered process. To illustrate this one of the RAGAGEP for establishing thickness-monitoring-locations (TML), API 510, Section 6.4., provides a specific requirement to establish TML, but it only provides generic/vague guidance on the locations and the number of TML required to be established for pressure vessel inspections. This section of API 510 requires pressure vessel inspectors to interpret what it meant by, "A representative number of thickness measurements must be conducted on each vessel…For example the thickness for all major components (shells, heads, cone sections) and a representative sample of vessel nozzles should be measured…" . Using only the generic guidance provided by this RAGAGEP for establishing TMLs would not comply with the requirements, because the employer has the responsibility to develop a MI program procedure that clearly establishes the specific number and locations of TML for each of their pressure vessels. By establishing MI program procedures which provide clear requirements, employers assure that inspectors are conducting thorough inspections of their pressure vessels. Other examples of RAGAGEP could include API 653, API 580, and NBIC (National Board Inspection Code).

For non-metallic (such as fiberglass and resin materials) vessels and piping the site still must develop a MI procedure to ensure the vessels and piping meet needed specifications. CCPS stated it well in their Guidelines for Risk Based

Process Safety, Chapter 12, when they said "Regardless of the procedures, tools, and other conditions, the ultimate measure of success for the asset integrity element is ensuring that equipment remains fit for its intended purpose,…." CCPS, Guidelines for Mechanical Integrity Systems in Chapter 9 states, "Design, fabrication, and testing for fiberglass vessels, tanks, and equipment are contained in several RAGAGEPs published by API, American Society of Mechanical Engineers (ASME), and the American Society of Testing and Materials (ASTM) International. However, these RAGAGEP generally do not provide specific guidance on the inspection and testing of in-service equipment. Common RAGAGEPs for fiberglass constructed equipment are: ASME Section X…API Spec 12P…ASTM D2563…ASTM D2583."

Question 2: Do the vessel and piping inspections follow the procedures identified in Question 1? Provide brief description of documentation protocol(s) (How are these inspections documented and maintained?).

Question 3: For mechanical integrity issues and deficiencies found in vessels or piping (e.g., thin spots, corrosion, cracks), what are the procedures to address found deficiencies to ensure safe operation? Do these procedures follow RAGAGEP, and have they been followed?

Question 4: Does the MI procedure indicate how the testing (e.g. leak testing) and repair will be conducted and which personnel are authorized to do the testing and repair, including what credentials those conducting the testing and repair must have? Provide examples of the credentials needed/utilized?

Guidance: RAGAGEP that require credentials include, but are not limited to:

1) Credentials for pressure vessel inspectors. see API 510, Section 4.2.

2) RAGAGEP for pressure vessel examiners credentials/experience and training requirements, see API 510, Section 3.18.

3) RAGAGEP for contractors performing NDE are the training and certification requirements American Society of Non-Destructive Testing(ASNT)-TC-1A, see CCPS Guidelines for Engineering Design for Process Safety, Section 10.3.2.1, (In-service Inspection and Testing) Nondestructive Examination.

4) RAGAGEP for qualifications for personnel who conduct pressure vessel repairs, alteration and rerating including qualifications for welders, see API 510, Section 7.2.1 and the ASME Boiler and Pressure Vessel Code (BPVC), Section IX.

5) RAGAGEP for certifications at CCPS Guidelines for Mechanical Integrity Systems, Section 5.4 Certifications, Table 5-3, Widely Accepted MI Certifications, and Table 9-13, Mechanical Integrity Activities for Pressure Vessels.

6) RAGAGEP requiring the employer to detail the qualifications of inspection and repair personnel (including contract employees) at API 510, Section 4.3. This section requires the owner-user to develop a quality assurance inspection manual which must include requirements for using only qualified inspection and repair personnel per subsections (g), (i), (j), and (k).

This training requirement applies to both host employer's and contractor employer's employees performing MI procedures. CPL 02-02-045, Appendix B, pg. B-27, states, "If contract employees are involved in…maintaining the on-going integrity of process equipment, then they must receive training in accordance with specific training requirements set forth in paragraphs (g) and (h), respectively").

Question 5: Is Process Safety Information for safe upper and lower limits and the results of the evaluation of consequences of deviations (including the steps to avoid or correct deviation(s)) consistently incorporated into the written operating procedures for availability to operators?

Question 6: Do the Emergency Shutdown Procedures (ESPs) specify that qualified operators are assigned authority to shutdown the unit(s)? Are qualified control board operators authorized or permitted to initiate an emergency shutdown of the unit without prior approval? If so, in what procedure or where in each procedure is the authority given?

Question 7: For the design and design basis calculations for pressure relief for the process, provide examples of how your site calculates the flow-induced pressure drop in the inlet piping and backpressure considerations for conventional pressure relief valves (PRVs)?

Guidance: API 520 Part 1-2008, Section 5.3.3.1.1 states, "Conventional PRVs show unsatisfactory performance when excessive backpressure develops during a relief incident, due to the flow through the valve and outlet piping. The built-up backpressure opposes the lifting force which is holding the valve open."

Section 5.3.3.1.2 states, "Excessive built-up backpressure can cause the valve to operate in an unstable manner. This instability may occur as flutter or chatter. Chatter refers to the abnormally rapid reciprocating motion of the PRV disc where the disc contacts the PRV seat during cycling. This type of operation may cause damage to the valve and interconnecting piping. Flutter is similar to chatter except that the disc does not come into contact with the seat during cycling." In general, API 520 Part 1 Section 5.3.3.1.3 provides criteria stating, "In a conventional PRV application, built-up backpressure should not exceed 10 % of the set pressure at 10 % allowable overpressure…", although certain conditions can exist to exceed 10% (See API 520 Part 1, Section 5.3.3).

The flow-induced pressure drop in the inlet piping guidance is located in API 520 Part 2-August 2003, Section 4.2.2 "Size and Length of Inlet Piping to Pressure- Relief Valves

When a pressure-relief valve is installed on a line directly connected to a vessel, the total non-recoverable pressure loss between the protected equipment and the pressure-relief valve should not exceed 3 percent of the set pressure of the valve except as permitted in 4.2.3 for pilot-operated pressure relief valves. When a pressure-relief valve is installed on a process line, the 3 percent limit should be applied to the sum of the loss in the normally non-flowing pressure-relief valve inlet pipe and the incremental pressure loss in the process line caused by the flow through the pressure-relief valve. The pressure loss should be calculated using the rated capacity of the pressure-relief valve. Pressure losses can be reduced by rounding the entrance to the inlet piping, by reducing the inlet line length, or by enlarging the inlet piping. The nominal size of the inlet piping must be the same as or larger than the nominal size of the pressure relief valve inlet connection as shown in Figures 1 through 3. Keeping the pressure loss below 3 percent becomes progressively more difficult at low pressures as the orifice size of a pressure-relief valve increases. An engineering analysis of the valve performance at higher inlet losses may permit increasing the allowable pressure loss above 3 percent. When a rupture disk device is used in combination with a pressure-relief valve, the pressure-drop calculation must include the additional pressure drop developed by the disk (see 4.6 for additional information on rupture disk devices)." Other references for this guidance include International Standards Organization (ISO) ISO 4126 Part 9 Section 6

Question 8: For mechanical integrity issues and deficiencies found with relief devices (e.g., poorly functioning relief valves or visual inspection deficiencies), what are the procedures to address and prevent found deficiencies to ensure safe operation?

Guidance: API 576, Section 6 provides guidance into the inspection of relief devices. Section 6.1.1 states, "Failure of pressure-relieving devices to function properly when needed could result in the overpressure of the vessels, exchangers, boilers, or other equipment they were installed to protect. A properly designed, applied, and installed pressure-relieving device that is maintained in good operating condition is essential to the safety of personnel and the protection of equipment during abnormal circumstances. The principal reason for inspecting pressure-relieving *devices is to ensure that they will provide this protection.*

API 576, Section 5 discusses examples of "Causes of Improper Performance". More detail is provided in this section, but a brief overview in Section 5.2.2 states, "There are many causes of damaged valve seats in refinery or chemical plant service, including the following.
a) Corrosion.
b) Foreign particles introduced into the valve inlet and pass through the valve when it opens, such as mill scale, welding spatter or slag, corrosive deposits, coke, or dirt. The particles may damage the seat contact required for tightness in most pressure-relief valves. The damage can occur either in the shop during maintenance of the valve or while the valve is in service.
c) Improper or lengthy piping to the valve inlet or obstructions in the line. These can cause a valve to chatter. The pressure under the seat may become great enough to open the valve. However, as soon as the flow is established, the built-up pressure drop in the connecting piping may be so great that the pressure under the seat falls and allows the valve to close. A cycle of opening and closing may develop, become rapid, and subject the valve seating surfaces to severe hammering, which damages the seating surfaces, sometimes beyond repair. Figure 27 and Figure 28 show seating surfaces damaged by chattering and frequent fluctuations of pressure.
d) Careless handling during maintenance, such as bumping, dropping, jarring, or scratching of the valve parts.
e) Leakage past the seating surfaces of a valve after it has been installed. This leakage contributes to seat damage by causing erosion (wire drawing) or corrosion of the seating surface and thus aggravating itself. It may be due to improper maintenance or installation such as misalignment of the parts, piping strains resulting from improper support, or complete lack of support of discharge piping. Other common causes of this leakage are improper alignment of the spindle, improper fitting of the springs to the spring washers, and improper bearing between the spring washers and their respective bearing contacts or between the spindle and disk or disk holder. Spindles should be checked visually for straightness. Springs and spring washers should be kept together as a spring assembly during the life of the spring. Seat leakage may also result from the operating pressure being too close to the set pressure of the valve.
f) Improper blowdown ring settings. These can cause chattering in pressure-relief valves. The relief valve manufacturer should be contacted for specific blowdown ring settings for liquid service and for vapor service.
g) Severe oversizing of the pressure-relief valve for the relief loads encountered can cause the valve to close abruptly, resulting in disc and nozzle seating surface damage."

Question 9: Does the host employer periodically evaluate the performance of contractors to assure that the contractor's employees are following all the obligations required of contractors under the PSM standard? As an example briefly describe the selection and oversight of contractors performing hot work and confined space entries at the site.

Guidance: The employer must be able to show how it satisfied/performed its obligation to assure that they are periodically evaluating the performance of their contractors in fulfilling their obligations under the PSM standard. The host employer method to conduct these contractor evaluations, and the frequency are matters for the host employer to determine and would be typically based on factors including, but not limited to, the type of contractors at the facility (nested or short term), the number of contractors and their employees, the type and risk associated with the work the contractor's perform (e.g., opening process equipment, confined space entry, hot work, asbestos abatement, vessel/piping inspections, etc.). As part of this "host employer's determination" the PSM standard's employee participation paragraph requires the host employer to consult with its employees on the development of all elements of PSM, including "Contractors" provisions. Determine whether the host employer at least follows its own contract employer evaluation processes, if these processes exist (A host employer program for evaluating contract employer's safety information and programs is not a requirement of the PSM standard).

Question 10: Does the employer audit its safe work practices/procedures for opening process equipment, vessel entry, and the control of entrance to a facility or covered process area?

Guidance: An employer must audit the procedures and practices required by PSM and ensure they are adequate and are being followed, especially important basic procedures like those listed above. OSHA expects that employers would audit both the developed safe work practice and its implementation. Based on interviews with host and contract employer *personnel (operations and maintenance), are hot work permit procedures (including the issuance of hot work permits) followed?*

Question 11: How is the site ensuring that RAGAGEP for mechanical integrity is being followed? Does the PSM compliance audit evaluate the site's history of following RAGAGEP and the site's MI procedures?

Question 12: Does the site have unresolved Process Hazard Analysis (PHA) recommendations, which the site is currently tracking? How long have open recommendations been unresolved and are any past target dates? Basically, how does the site ensure PHA recommendations are corrected in a timely fashion?

Question 13: How does the facility ensure that Piping and Instrumentation Diagrams (P&IDs) are kept up-to-date and accurate? Are the P&ID's up-to-date and accurate?

Question 14: Has the employer inspected, tested, and calibrated the controls (including monitoring devices and sensors, alarms and interlocks) in the Selected Unit(s)? If so, what RAGAGEP is the site using? If using the International Society of Automation (ISA) S84.01, is the company current with all testing?

Guidance: CCPS, Guidelines for Mechanical Integrity, 2000 includes examples of other RAGAGEP's that contain requirements for maintenance, testing, and inspection of instrumentation and controls. In particular see Table 9-5, RAGAGEPs for Instrumentation and Controls and Table 9-12, Mechanical Integrity Activities for SIS (Safety-Instrumented-Systems) and ESDs (Emergency Shutdown Systems).

Using the employer's identified "Safety Critical" controls list for controls in the Selected Unit(s), identify 6 different controls and determine if the employer has inspected, tested, and calibrated these 6 controls per its mechanical integrity procedures and applicable manufacturers' recommendations. (Note: ANSI/ ISA S91.01-1995, "Identification of Emergency Shutdown Systems and Controls That Are Critical to Maintaining Safety in Process Industries", an example RAGAGEP, requires that employers establish a procedure to identify the emergency shutdown systems and safety critical controls that are key to maintaining safety in the process industries as defined in the Mechanical Integrity sections of the PSM standard) If the employer has not identified its safety critical controls, use the Selected Unit(s) P&IDs to identify 6 controls to determine the above information.

Question 15: Who reviews the results for the safety system controls (including monitoring devices and sensors, alarms and interlocks) inspection, testing, and calibration? What are the procedures to address found deficiencies to ensure safe operation?

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