MEG Energy Corp.
Steam Pipeline Failure
Licence No. P 46441, Line No. 001
May 5, 2007

ERCB Investigation Report

September 2, 2008

Energy Resources Conservation Board

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ERCB Investigation Report: MEG Energy Corp. Steam Pipeline Failure, May 5, 2007

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1 Incident Overview

At about 5:33 a.m. on Tuesday, May 5, 2007, MEG Energy Corp. (MEG) became aware of a potential release situation at its Christina Lake Regional Project when the control room operator noted an “electrical blip and a muffled pop sound.” Communication was lost between the Digital Control System (DCS) and Pad A (location of six horizontal well pairs) and a large plume of steam was observed rising in the direction of Pad A.

The site is the steam assisted gravity drainage (SAGD) thermal heavy oil Phase I Pilot Project, located in a remote area near Christina Lake, about 150 kilometres (km) south of Fort McMurray.

MEG staff responded in the direction of the steam plume to confirm the location of the release but were stopped about half way to Pad A by sections of the aboveground 24-inch (610 millimetres [mm]) steam pipeline and downed power lines lying across the road. They also observed damage to the 4-inch (102 mm) lift gas and 24-inch production pipelines adjacent to the failed steam pipeline on the aboveground pipeline rack.

MEG mobilized a response team while operations staff began immediately to assess the situation. By 6:30 a.m., all personnel were accounted for and site electrical workers had completed the isolation of the electrical power lines in the corridor. MEG operators completed the manual isolation of the wells at Pad A by 7:00 a.m. and the manual isolation of the three affected pipelines at the plant and Pad A by 7:05 a.m.

The Energy Resources Conservation Board (ERCB) Bonnyville Field Centre (BVFC) was notified at about 7:15 a.m. and field inspectors were dispatched. The BVFC notified the ERCB Emergency Response Group (ERG).

MEG’s spill response trailer was brought to the site and absorptive containment booms were deployed around a culvert to ensure that no spilled product travelled beyond the initial spill area. The released material impacted an area about 100 metres (m) x 300 m, and the bulk of released bitumen was contained within a drainage ditch running along the east side of the well pad access road. At about 11:30 a.m., an aerial assessment was completed by helicopter to establish the extent of area involved and severity of the spill.

MEG commissioned a third-party investigation of the incident by Arc Metallurgical Inc. Sections of steam pipeline had been thrown in a number of directions within the right-of way and adjacent forest. Helicopter, quad, and foot searches were used to locate the pipe. All pipe segments were transported to a lay-down yard near the plant site and reassembled in the preincident upstream to downstream orientation. Aids for reconstruction included remnant pipe identification numbers, weld map identifiers, and construction drawings.

On August 2, 2007, MEG was given approval by the ERCB to begin reconstruction with the understanding that the ERCB’s investigation was incomplete and the company would proceed at its own risk.

Reconstruction was conducted in stages as information was released by the Arc Metallurgical Investigation Team. Physical reconstruction of the pipelines was able to commence as no problems were identified with the materials or welding. As recommendations for physical modifications were developed, they were incorporated into the reconstruction efforts.

This facility is under joint regulatory authority and was investigated by both the ERCB and the Alberta Boiler Safety Association (ABSA). Meetings were held between MEG, the ERCB, and ABSA to discuss their respective incident investigations and the reconstruction.

On January 2, 2008, a site visit was conducted by the ERCB and ABSA to view the reconstruction. After the visit, a meeting was held with MEG to request additional information and to confirm dates of completion for installation of equipment.

On January 4, 2008, a meeting was held between the ERCB and ABSA to discuss the status of their investigations and the reporting structure of each organization.

On February 5, 2008, MEG was given approval by the ERCB to begin plant start-up. MEG was also reminded that this facility was also under ABSA jurisdiction and would require their approval as well for plant start-up.

On April 8, 2008, MEG was given approval by the ERCB for full pipeline operation.

2 ERCB Investigation and Findings

The ERCB conducted an investigation focused on the cause of the incident, the risk to public safety, and the environmental impacts. The following are the findings from the ERCB investigation.

2.1 Cause

The investigation determined that the failure resulted from a condensation induced steam hammer that generated forces well in excess of the breaking strength of the pipe.

2.1.1 Description of Condensation Induced Steam Hammer and Diagram

A condensation induced steam hammer is sometimes called a condensation induced water hammer or a steam bubble collapse and is a rapid condensation event. It occurs when a steam pocket becomes totally entrapped in subcooled condensate. As the steam gives up its heat to the subcooled condensate and pipe walls, the steam changes from a vapour to a liquid. The continued loss of steam by this phase transformation induces fresh steam to flow into the steam pocket in order to replace the lost steam. Steam flow over condensate will tend to draw up waves in the condensate via the Bernoulli Effect. If the rate of heat transfer is rapid enough for a given condensate level, the induced steam velocity will draw up a wave high enough to seal the pipe. This is critical because the wave seal effectively isolates the steam pocket from the upstream supply of steam. At that instant, ongoing condensation causes the vapour void to collapse because the volume of liquid is about 100 to 1000 times smaller than the precursor volume of steam. The associated drop in pressure within this void acts like a vacuum that causes the condensate waves to crash into each other. There are also rebounding shockwaves (see Figure 1).

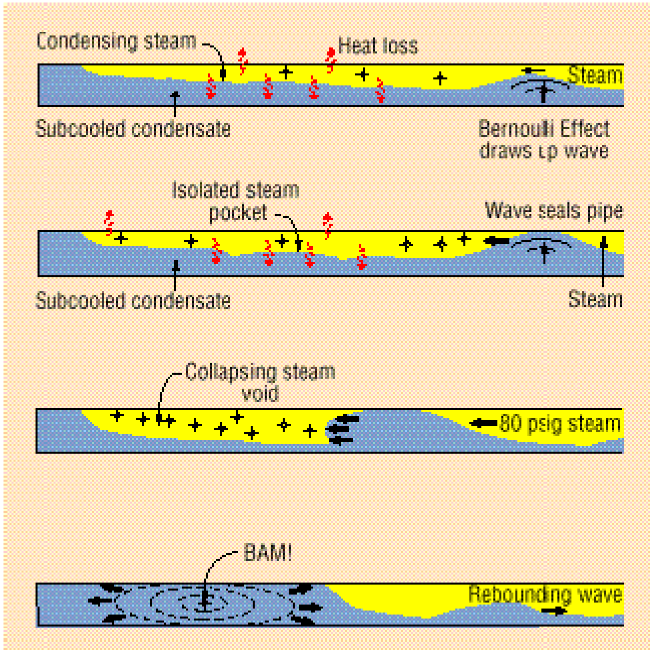

Figure 1. Condensation induced water hammer

The conditions for the condensation induced steam hammer were created by an inadequate operating procedure and design changes during construction.

The operating procedures were written at a high level that did not include sufficient detail regarding procedures for heating, monitoring, draining, and pressuring the steam header. Detailed steps were left to the discretion of the individual operators. Consequently, the system was warmed differently by the various shift operators.

The steam pipeline design underwent changes during construction related to the removal of drain tanks and a reduction in the number of drains. Consequently, the steam pipeline went into service without adequate procedural controls and instrumentation to guard against potential hazards.

The failure of the 24-inch steam pipeline and the ensuing pipe whip and energy release damaged portions of the adjacent lift gas and production pipelines, as well as trees, support structures, and a small metal building. The actual duration of the incident is unknown but the damage to the pipe likely only lasted a few seconds followed by several minutes of pressure release from the steam pipeline.

The pipe material and welding met specification requirements and showed no evidence of material defects, pre-existing cracks, or embrittlement meaning that the failure resulted from mechanical overload.

2.2 Public Safety / Emergency Response

This portion of the investigation was to assess the response of MEG and the actions undertaken to manage the incident. All required agencies were contacted (ERCB, Alberta Environment [AENV], Environment Canada, Alberta Sustainable Resource Development [ASRD; Fish and Wildlife, Lands, and Forestry], and Alberta Employment, Immigration and

Industry [Workplace Health and Safety]). MEG had an appropriate response to the incident and immediately brought in all the necessary resources.

The failure occurred in a remote area with no impact on public health or safety. There were no residents within 15 km of the incident site and no public access.

The communities of Conklin, Chard, and Janvier were informed of the incident on May 10, 2007. A follow-up meeting and site tour were held on May 17, 2007, with the Chipewyan Prairie Dene First Nations, including the chief and council of the Janvier Band, band elders, and representatives of the Industrial Relations Council. In addition, information about the incident was made available in an open house session in Conklin on May 29 as part of MEG's public consultation for its proposed Phase IIB development.

The ERCB investigation concluded that at no time during the incident was public safety at risk.

2.3 Environmental Impact

The spill occurred in a remote wooded area. Spill cleanup and remediation of the impacted area began immediately in the most affected area, about 50 m x 100 m, which had small trees that were heavily covered with bitumen that on cooling formed a stable and solid coating 2–3 inches thick. In consultation with ASRD, some trees were removed to ensure maximum recovery of bitumen and remediation was deemed complete within a month.

Environmental consultants arrived on site on the morning of May 7, 2007, to assist in more intensive water and sediment sampling. After allowing for further bioremediation of the site, representatives returned to the site in September to conduct follow-up sampling of the impacted area. Results indicated that contaminated source material had been successfully removed.

Contaminated material was hauled away to the Eveready Pembina Class I landfill near Drayton Valley. Following waste characterization for hydrocarbon content by AGAT Laboratories, it was determined that the waste material qualified as nonhazardous waste and was disposed of at the Class II CCS landfill near Janvier in accordance with AENV requirements.

2.4 Resource Conservation

The spill volume was estimated to be 200 cubic metres (m^3) of steam condensate, 632 m^3 of natural gas, and 10 m^3 of produced bitumen.

3 Follow-up Actions

3.1 MEG

As a result of the incident and the ERCB investigation, MEG intends to implement all of the *Arc Metallurgical Inc. Failure Analysis Report Recommendations* (see appendices) unless they prove to be unfeasible after more detailed design or attempted implementation. In addition, better alternatives may be found after further work. In any event, all of the issues that the recommendations are aimed at will be addressed.

The investigation has provided a detailed look at the causes and prevention of a phenomenon, condensation induced steam hammer, which has not been a common occurrence in the oil and gas industry. Accordingly, it is MEG's intention to communicate the results of the investigation to other oil sands operators with similar steam pipelines in order to improve industry understanding. The format and timing for this has not yet been finalized.

3.2 ERCB

1) The ERCB will continue to develop follow-up actions with MEG and to update the ERCB Incident Response and Reporting Protocol Review Committee.
2) The ERCB and ABSA will develop a joint document clarifying to industry the jurisdictional division between the two agencies and provide guidance on ABSA and ERCB roles. This item will be completed by spring 2009.
3) The ERCB, through the BVFC, will take enforcement action against MEG for
    - failure to notify the field centre of pipeline construction in accordance with *Directive 066: Requirements and Procedures for Pipelines*, and
    - failure to have an operations and maintenance procedures manual dedicated specifically to pipelines in accordance with Section 7 of the *Pipeline Regulation* and Clause 10 of *CSA Z662-07: Oil and Gas Pipeline Systems*.

    MEG successfully addressed the enforcement actions on April 8, 2008.

Wellhead valves on the injection side should be programmed to close and stay shut-in during steam outages.

Care should be taken to ensure that the pipeline is constructed so that the designed low point remains the low point after construction.

All pipelines should be designed with drains in such locations that they can have condensed water removed during start-up.

Steam pipelines must be warmed up slowly and kept drained during the start-up .

The procedure for steam pipeline and steam system warm-up should be revised to include controls and steam system safeguards.

Consideration should be given to developing criteria for surface instability. Criteria may provide parameters to specify the maximum warm-up rate in any section containing condensed water.

Add safeguarding through mechanical means and DCS shutdown key logic. Mechanical safeguards should include valves and piping designed to warm-up and pressurize the steam system in a way that would not allow sudden acceleration of condensate. This should begin at the steam generator blowdown and motor operated valve (MOV) and include the wellheads and valving at the well pad. Wellhead valves and A-PCV-0001A/B should be included in shutdown key design for redundancy in the safeguards.

Valve and piping design for steam system warm-up and pressurization should include safeguards to ensure smooth operation of the steam generator and eliminate the risk of sudden acceleration in the system. Reliability issues with the steam generator must be resolved prior to start-up. One previous issue was that water-flow control-valve sizing problems were causing nuisance steam generator shutdowns which contributed to water accumulation within the steam header.

Water entry to the steam header should be avoided as it increases the risk of damage to the steam pipeline and downstream equipment during both warm-up and steady-state operations. Safeguards through shutdown key logic should be added to ensure water entry does not occur. For example, shutdown key initiating alarms for steam out temperature and steam separator level should be developed.

The steam pipeline control system requires additional instrumentation to monitor start-up in order to identify sub-cooled condensate and reveal conditions having the potential to accelerate same, including:

- flow rate entering the pipeline,
- pressure and temperature upstream of the PIC valves,
- critical-valve position proving switches (include in control logic as appropriate),
- interlocks on A-PIC-0001A/B valves to ensure correct ramp rates,

- interlocks on hand indicating control (HIC) valves to prevent high velocities during start-up.

The liquid in the pipeline can be a hazard if not properly managed. However, the risk of a similar incident would only occur under certain calculable conditions that can be avoided by either removing the liquid or safeguarding the control system, as follows:

- the first option requires a pipeline drain system at Pad A to ensure the pipeline is drained prior to introducing steam. The system should drain any accumulated condensate prior to start-up and during normal operation. Activation of the drain should be automated.

- the second option which may be more practical in situations where the well pad is not at the low point in the pipeline (or where there are multiple low points) is to measure the temperature of the condensate at the low points and corresponding vapor spaces. These temperatures in turn should be compared to the supply pipeline steam temperature so that permissives in the DCS logic can be used to ensure critical subcooling conditions are avoided.

Review the steam/production pipelines design, including design criteria, stress calculations and support structure prior to start-up.

Update operating procedures to reflect report recommendations, current operating practices and incorporate more details around steam flow pipeline operations. Ensure a ‘management of change’ process is in place to archive progressive revisions of operating procedures.

Separate facility operating procedures from pipeline operating procedures to accommodate ERCB requirements for a “Pipeline Operating Manual” for steam, production, gas, source water and disposal pipelines. Include emergency pipeline shutdown procedures.

Develop a documented system for training and qualifying operators.

Perform risk assessments on operating procedures to identify those that must be kept updated and incorporated into training plans.

Add facilities required to slowly warm up and monitor the steam and production pipelines:

- Add sacrificial valve to bypass around the once through steam generator OTSG motor operated block valve to allow slow warm up of the steam pipeline and steam separator out to the header block valves.
- Add a sacrificial valve to the bypass around the steam header block valves downstream of the HP steam separator to allow slow warm-up of the steam header to Pad A.
- Remove the line connecting Pad A steam header drain to the production header at the pipeline low point drain and convert to steam header drain only (Line No. S-0057-2”-D7-50H and Line No. BD-0001-2”-C7-50H).
- Add facilities to make draining condensate at Pad A practical, e.g. access, catch basin/tank, truck out and be prepared to haul back to the plant or pond for disposal.
- Add temperature monitoring on the steam header to monitor warm-up progress.
- Add sacrificial valve to Pad PIC 0001 to allow slow warm-up of the pad steam header.

- Add drain and collection facilities to collect drained condensate from the ‘future expansion’ blind flange on the end of the pad header.

Determine steam pipeline conditions that would allow a hot start-up procedure to be applied.

The design of steam pipelines should consider possible interaction between process dynamics and structural dynamics.

Procedures should be in place to ensure ‘systems design’ and ‘management of change’ are upheld.

The reliance of the system to operate within the design envelope should be a function of design and appropriate operational procedures that manage the risk. If it is a requirement to control the functions of the system with procedures, the potential safety hazards should be well managed. Close interaction between design and operations is a requirement.

Avoid design low spots such as those provided by concentric reducing tees.

The alarm log and the time of an actual event should be synchronized (presently 6 hours in arrears variance).

Pipeline design engineers should conduct field inspection of the as-built pipelines prior to restart to ensure design intent has been met.

The as-built slope of the steam pipeline should be surveyed to ensure conformance with design. Tolerances on slope should be specified.

Review existing construction quality and control processes, amend as necessary.

Conduct periodic audits to ensure compliance with the controls processes.

Ensure inspection and test plans are in place and utilized (having an ITP in place for any construction phase or activity provides a sound foundation for controlling and assuring the work).

An owner inspector should be involved throughout the construction phase to review and sign-off on the quality assurance and control documentation.

Outstanding close-out items from Phase 1 construction will be reviewed and where possible reconciled.

The preheat and interpass temperatures should be maintained for the duration of the welding of a circumferential weld.

If a delay/interruption of the welding is unavoidable, the preheat should be maintained. If the preheat cannot be maintained the partial weld should be subjected to full non destructive examination NDE prior to resuming preheating and welding.

Weld consumables should be stored and managed as per the manufacturer’s recommendations.

The welding process and procedure as approved for the circumferential welds should be implemented as approved. Any increase in the volumetric ratio of the 80 ksi weld consumable versus the 100 ksi consumable must be avoided.

The transition slope where materials of different wall thickness join should be increased from the normal 1:3 to 1:5 or shallower.

Construction records and weld maps should include material identification including reference to new and recovered (used) materials, e.g. heat and joint number; welder identification and NDE reference.

In addition to radiography, consideration should be given to inspecting all new weld joints using phased-array ultrasonics.

Inspect all pipe-to-fitting welds and pipe-to-pipe tie-in welds using black on white magnetic particle methods no sooner than 72 hours after welding.

Include a bypass control valve (manual or automated) around the MOV to improve system operability. The installation of a flow meter registering the flow into the steam pipeline may have significant benefit especially later in the life of the plant's operation.

Perform stability tests prior to the final re-start of the plant, e.g. BFP stable on minimum flow; boiler stable on minimum fire; and the back pressure control with 1-PIC-3051 on auto.

Install temperature probe/probes to measure the temperature of the condensate at the low point, and facilitate interlocks to safeguard against sub-cooling.

Control system security issues need improvement and control system ownership should be established (the control system main administrative password was not available for testing instrumentation at the well pad). Procedures and a change management process including approvals should be implemented.

Implement a communication verification program between the central plant facility and the well pad to initiate a well pad unit shutdown on loss of communication and automatically shut-in well pad and isolate all valves should operations be unable to physically access the well pad during a critical situation (time out gate functionality).

Process descriptions and process control descriptions should be developed to provide details of control system functionality and process interaction.

The existing practice of throttling of the steam generator steam outlet MOV to provide back pressure on the steam generator is not recommended as this valve was not designed for throttling service and will eventually be damaged (see also Ref: 07-0198 RAE Engineering Report Section 3.3 Conclusions for operation of steam generator discharge MOV).

Troubleshoot and re-design/fix OTSG and boiler feed water BFW pump operation to minimize downtime/outages. Once steam pipeline/production is going, avoid frequent shutdowns/re-starts to minimize thermal cycling the steam pipeline.

Review the OTSG fuel flow control loop components and programming for application suitability, and make changes that will permit the unit to run stable at minimum turn down rates.

Review BFW/blowdown exchange loop design and develop procedure to start up system without exceeding BFW pump design temperature rate changes and maintain steam separator level.

Log books should be maintained for each area of responsibility and entries signed by the appropriate operator.

Operations staff should to be assigned to a specific area of responsibility while on shift. This should not discourage training or assistance in other areas but would give direction to who is responsible for what equipment.

Develop a checklist to ensure pipeline isolation valves are inspected and functioned in accordance with the requirements of Z662 Section 10.6.6.2.

Remove the line connecting Pad A steam header drain to the production header on the pad downstream of PIC 0001 and revamp to use as a steam pipeline drain (Line No. S-0008-2”-CH-50H-ET).

Apply all recommendations to Phase 2 and future installations.

Ensure the HAZOP identifies responsibilities, preparation, and implementation, reporting and close-out. MEG Energy involvement in the HAZOP should be increased and peers from WPMEG should participate as well.

Develop a ‘MEG Energy pipeline basis of design’ document. This document should provide a clear overview of design management including work flow and analysis and should be formatted to provide an auditable base to ensure regulatory codes, standards and project specifications are met.

Re-assess the management process for developing the pipeline system design. Measures should ensure that project specific obligations and regulatory codes and standards are met.

Ensure the design work complies with sound engineering practice and necessary codes. Follow-up reporting should clearly state objectives, scope, references, dependent calculations and conclude on whether the design is acceptable.

Ensure the designer provides a written report summarizing design calculations and certifying that the design was performed in accordance with CSA Z662 and ASME B31.3 Chapter IX under the ABSA Variance VA05-001.

Pipeline design engineers should consider field inspection of as-built works prior to pipelines start-up to ensure design intent has been met. This would be a prudent step in the design assurance process and would supplement on-site construction inspection.

Appendix B Actions to be Completed During the Third Quarter 2008 by MEG

The number of alarms should be addressed. There are two recommendations which enhance the evaluation of alarms. The first is to write control narratives which may be used by the operators to better understand the nature and importance of an alarm and thereby make better response decisions. The second is to establish an alarm philosophy and eliminate unnecessary alarms accordingly.

Alarm management should be implemented on the control system. Nuisance alarming adds confusion and makes it difficult to operate the facility. Troubleshooting and analysis of the alarm log is required during both normal and abnormal operating conditions otherwise these operating tasks become more time consuming and difficult than necessary.

The alarm philosophy should be reviewed to reduce or eliminate repeat alarms from registering.

The integrity of the facility and shutdown systems must be better protected. The control system back-up procedure should be documented and include a plan to recover data from the back-ups. Loss of control system power should not affect critical data.

Refine handover/start-up/commissioning plans for Phase 2 and beyond (clear budgets, schedules, RACI charts, start-up systems, procedure development, training plans, etc).

As required by the Project Execution Plan 085342-1012-0001, ensure that the Joint Venture submits one complete copy of the as-built dossier in hard format and one electronic format (Section 2.1.9.5). In addition, ensure that the Joint Venture prepares the necessary design manuals (Section 2-15).

Two aspects of the pressure control station valve operation 1-PIC-0001 valves should be addressed. The first is to prevent rapid opening and the second to prevent the valves from acting on an opening signal if they are stuck in the closed position. This could be achieved by incorporating a positioner or by making use of limit switches and logic control.

Operability issues caused by control system deficiencies need to be resolved.