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December 13, 2016

Marie Therese Dominguez
Administrator
Pipeline and Hazardous Materials Safety Administration
East Building, Room E27-314
U.S. Department of Transportation
1200 New Jersey Ave, SE
Washington, DC 20590-9898

Re: PHMSA Interim Final Rule on gas storage

Dear Administrator Dominguez,

Thank you for this opportunity to comment on PHMSA's Interim Final Rule (IFR) on natural gas storage. On behalf of the States First Initiative, the Interstate Oil and Gas Compact Commission (IOGCC), the Groundwater Protection Council (GWPC), and other experts, we submit detailed comments on the American Petroleum Institute's Recommended Practices 1170 and 1171, which are the basis of the IFR.

The purpose of these comments is twofold. First, we highlight for PHMSA both gaps in the coverage of the Recommended Practices with respect to key issues for regulating the lifecycle and full scope of gas storage projects. Second, we point out areas where a provision from the Recommended Practices would be difficult for PHMSA to implement as a regulation – for example, because of vagueness, ambiguity, or insufficient detail.

The comments are intended to provide considerations for PHMSA about how to interpret and build upon the Recommended Practices to create a robust and actionable regulatory program. This includes specific information PHMSA will need to implement particular provisions.

We hope also this analysis gives PHMSA insight into the expertise and capacity – in terms of staffing and otherwise – it will need to successfully manage this program while enhancing safety and protecting public health and the environment.

The States First Initiative, IOGCC and GWPC look forward to being full partners with PHMSA as it develops and implements its regulations and regulatory program, and we hope to provide our expertise on regulating gas storage to PHMSA on an ongoing basis.

Please let us know if we can provide clarification or more information about any of the topics raised in these comments.

Sincerely,

Harold R. Fitch
Co-Chair, Gas Storage Work Group
& Chief, Office of Oil, Gas & Minerals
Michigan Department of Environmental Quality

Richard J. Simmers
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Co-Chair, Gas Storage Work Group
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Ohio Department of Natural Resources

Comments on API RP 1170 and 1171

The "States First" Gas Storage Workgroup has reviewed API RP's 1170 and 1171 with respect to their suitability as a regulatory framework for the underground storage of natural gas and natural gas liquids. While the RP's contain substantial information and guidance regarding underground storage, it is our belief that they require considerable wording revisions and additions to make them effective as regulation. The following comments represent the opinions of specific reviewers and may or may not represent a consensus opinion of the entire workgroup:

1. The RP's do not address the issue of Risk Management with sufficient specificity. Notably, there is no recommended practice that describes how much risk is acceptable using systems such as the As Low As Reasonably Practical (ALARP) principle. Further, the API etal. "white paper" (p. 82, Appendix 6.3) specifies that each operator set's their own risk management objectives in the context of their company's "capability". This concept is antithetical to regulatory management; which requires all operators meet an established standard irrespective of their self defined "capabilities".
2. A number of documents would be required to obtain approval for storage service from a regulator. Given this is a new process, with new rules and a new regulator, then a process would be required to officially permit the facility under the new rules and provide all the documents required in this regulation. Essentially proved that each facility is compliant with the new rules. Existing facilities should go through a re-permitting process to guarantee compliance.
3. The RP's use the term "should" extensively throughout the documents. This term is inconsistent with regulatory language. In order to be enforceable a regulations use the terms "must" or "shall". The term "should" is merely suggestive of something that might be done but which is not required. Regulations cannot be enforced on that basis.
4. RP's should specify level of exposure of facilities: includes proximity to company or public assets, and also any previous safety or process issues at any given storage facility. Likelihood of occurrence (used to calculate risk) is quite high for facilities that have experienced at least one event (e.g. Yaggi, Aliso Canyon, McDonald Island). Such facilities should be subject to a higher level of regulatory scrutiny than those that have not experienced failure events.
5. RP's should address spill prevention and control plans and some sort of spill retention system around each well.
6. API itself has recognized that the RP's are "not intended to replace federal, state, or local regulations". However, if the RP's are used as the basis for federal regulations that is precisely what they will be doing, at least with respect to federal regulation. Merely referencing or copying sections of the RP's in a regulation would not provide a proper basis for regulatory control inasmuch as there appear to be gaps that could create regulatory uncertainty or inadequacy. This is clear in many of the sections reviewed by the Gas Storage Workgroup members as outlined in the examples below:

   RP 1170:

   - 1.2 Applicable Rules and Regulations: There is no mention in this section about the role of the Underground Injection Control (UIC) program within the context of gas storage. For example the solution mining of caverns for gas storage would typically be considered a Class III UIC activity for which a UIC permit would be required.

- 4.2 Types of Underground Natural Gas Storage: This section addresses only three types of gas storage. It does not include any information on other storage such as in mined caverns, converted mines, and hard rock caverns.
- 4.5 Overview of Major Steps in the Development of Gas Storage Cavern: Same comment as for 1.2 above concerning lack of information about the role of the UIC program.
- 5.2 Site selection Criteria: No mention is made of proximity to sensitive surface and near subsurface features such as in urban areas, near surface water, proximity to pipelines etc…. Further, 5.2.3 needs to discuss state and local regulations on water extraction from surface water and water wells and the use of surface impoundments.
- 5.3 Geologic Site Characterization: This section needs to be expanded to include disposal formations, fresh water zones, and oil and gas formation on the flank of domes. This section should also discuss geophysical well logging program needs such as gamma ray, litho-density, neutron, dipole, caliper and other logs needed to properly analyze salt for geomechanical properties. There is no mention of a requirement to submit geophysical logs, core data or photographs, or cuttings to the regulatory agency. Some of these may be necessary for regulatory evaluation. Clarification is also needed with respect to the relationship between geologic uncertainty and risk.
- 5.4 Geomechanical Site Characterization: The RP lists only two in-situ stress state measures in rock surrounding a salt dome or bedded salt. In-situ stress requires specifying five values not just vertical and one horizontal stress magnitude. Further, a variety of tests including stress, strain, tension, compression, compressive stress and temperature of salt and non-salt formations is needed and such tests need to be submitted to the regulatory agency.
- 5.5 Assessment of Cavern Stability and Geomechanical Performance: This section does not address a standard set maximum pressure equation, but rather discusses how it could be evaluated. This lack of specificity results in regulatory problems when determining what pressure is appropriate for the cavern to ensure integrity still occurs.
- 6.2 Hole Section Design: Does not address the issue of USDW's encountered after surface casing is run and set. Also does not address specific surface casing setting depth or annular space minimums.
- 6.3 Casing Design: No testing specifications for casing strings or cement jobs are noted. Further, no specifications regarding the use of "used" casings are present.
- 6.4 Wellhead Design: These are good recommendations. However there should be no regulatory requirement for the type of wellhead used other than the use of a BOP and able to withstand the permitted pressure. Regardless, Safety factors should be applied to design calculations to

provide additional margin of mechanical strength. Should comply with API 6A and be rated for maximum operating and test pressures.

- 7.1 Rig and Equipment: Ensuring the permit holder has the proper rig scheduled is not a duty of the regulator. This task generally falls to the drilling consultant. This section does not discuss the parameters for BOP testing.
- 7.3 Drilling Guidelines: Within the geological evaluation of the site, there should be a determination if H2S has been present in any formation that will be proposed. If there has been H2S present within the township then monitoring equipment will be required.
- 7.4 Logging: Based on section 7.4.3 there needs to be a description of when production casing logs should be run. Would they be required initially and or at some schedule timeline developed by the regulating agency? Cement bond logs should be required on all cemented strings to provide a baseline to compare against such logs as may be run in the future. Some consideration should be given as to whether the cement bond logs are run "under pressure".
- 7.6 Cementing: It should be noted that individual states may have requirements about the types of cement that can be used. Also needs to specify that cement should be either brought to surface on all strings or up into the next string,
- 7.7 Completion: Within this section there should be a discussion of when the depth of each tubing string should be adjusted.
- 8.2 Cavern Solution Mining Design: The Nitrogen/Brine interface MIT shall be run once the cavern is built to proposed size. There needs to be a pass/fail criterion set up. Section 8.2.5 states that cavern size needs to be measured by sonar surveys, but there is no discussion to frequency of surveys. in section 8.4.2.8 states that sonar surveys should be run without tubing present and could provide frequency, but should be up to the operator.
- 8.3 Cavern Development Phases: As part of development, operator should have implemented a subsidence observation grid capable of detecting very small levels of subsidence. This grid should be visited and recorded annually to monitor for subsidence. Further section 8.3.4 should contain a provision stating logs and any test run shall be submitted to regulatory agency.
- 8.4 Equipment: There should be a requirement for emergency shutdown equipment on wells at all times not just during certain activities. Also, a flow meter or electronic device should be installed to measure amount freshwater injected into the cavern and the amount of brine withdrawn from the cavern.
- 8.5 Instrumentation, Control, and Shut Down: There should be a requirement for a Supervisory Control and Data Acquisition (SCADA) system and over pressure protection or something equivalent for the cavern.

- 8.6 Monitoring of the Cavern: Section 8.6.7.4 should have special permit conditions placed on caverns that are located in salt deposits which have a history of methane trapped in the salt. The special permit condition should include a provision to perform more blanket depth test to ensure there is enough protection agency dissolution of the roof.
- 8.7 Workovers during Solution Mining: There should be a requirement for the inspector to be present once the tubing is removed from the well. The inspector should have authority to require a joint to be replaced. Workover operations should be proposed to and approved by regulator prior to implementing.
- 8.8 workover to Configure for Gas Storage Service: Logs or tests capable of detecting roof-production casing seat integrity should be required prior to beginning operations and periodically after. MITs must be witnessed by regulatory authority and should be done anytime that operator believes integrity may have been jeopardized.
- 8.9 Debrining the Cavern: The RP does not address the issues of Underground Injection Control (UIC) classification of wells used for solution mining or disposal of the brine.
- 8.10 Existing Cavern Conversions: There is a list of criterion within section 8.10.1 which should be reviewed, however the RP lacks the minimum regulatory framework to show what standards need to be followed in a detailed way. Also the RP fails to describe how the regulatory agency would proceed in the permitting process if one or multiple criterion fail to meet the current standards.
- 8.11 Cavern Enlargement: The RP does not discuss the protocols for the regulatory approval of cavern enlargement.
- 9.1 Minimum and Maximum Operating Limits: Minimum and maximum operating pressures should be set or approved by the regulatory agency. RP does not state how minimum and maximum operating pressures are defined. Regulatory agency should oversee these pressures.
- 9.2 Equipment: Section 9.2.2 should specify that an ESD valve should be installed at or very near the manual valves. These valves should be part of an ESD system that automatically shut in the cavern in the event of an emergency.
- 9.3 Instrumentation, Control and Shutdown: Production casing annulus should be continuously monitored for pressure changes that may indicate and integrity issue. General cavern components should have control and shutdown devices installed.
- 9.4 Inspection and Testing: Section should be much more comprehensive and include notification, schedules and test criteria.
- 9.5 Workovers: Proper well control equipment must be on the wellhead during any workovers and capable of allowing work under pressure.
- 9.6 Site Security and Safety: No discussion of SSSVs or surface safety valves. All safety valves must be properly calibrated and function tested per API Specification 14A/ISO 10432. Based on the location of the

operation would there be different safety protocol or would there be one standard for all operations?

- 9.7 Operating Administration: Section 9.7.4 states that records should be kept until facility is decommissioned. However it does not state what would be submitted to the regulatory agency. Records documenting cavern system development, operations, and maintenance should be maintained at least until the gas storage facility is decommissioned. The should include: geomechanical studies; drilling and completion reports and records; solution mining data; workover reports; sonar survey reports; MIT reports; gas temperature and pressure; injection/withdrawal history; instrument inspection and testing; safety (ESD) valve maintenance and testing; and non-destructive testing.
- 10.2. Holistic and Comprehensive Approach: Section 10.2 states that there is no one best or preferred method to monitor cavern system integrity. However, it should have a requirement that the operator shall demonstrate Cavern System, wellbore cavern, and wellhead integrity.
- 10.3 Integrity Monitoring Program: At a minimum there should be a base frequency for evaluating integrity of the system and accounting. Section should specify what actions are to be taken and by whom when a red-flag is identified.
- 11.2 Abandonment Design: There is no mention of permitting requirements for abandoning the Class III well and cavern or for the operator to submit a plugging procedure for approval by the regulatory agency.
- 11.3 Removal of Stored Gas: Does not include information on how much gas can be left in the cavern?
- 11.7 Sonar Survey: There is no discussion of limits in bedded salts due to rubble piles.
- 11.8: Long-Term Monitoring: Greater detail on subsidence monitoring needs to be included. Annual subsidence monitoring is recommended. Release of financial assurance instrument should not be allowed until a demonstration of gas removal, cavern equilibrium and lack of threat to environment or human health and safety is made.

RP 1171

- 3 Definitions and abbreviations: RP lacks definitions for MAOP, Risk Management Plan, cavern storage etc…
- 4.2 Functions of Underground Natural Gas Storage: This is informative but does not belong in a regulation.
- 4.3 History of Underground Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs: This is informative but does not belong in a regulation.
- 4.4 Geotechnical Aspects of Underground Natural Gas Storage: This section does not contain recommendation about how a regulator should evaluate geotechnical aspects of a storage project.
- 5 Functional Integrity in the Design of Natural Gas Storage Reservoirs: Does not specify need for a permit for a new well or conversion of an oil and gas well to a gas storage well.
- 5.2 Geological Reservoir Characterization: The RP lacks information on what would be required geological information to submit at the time of permitting a new depleted natural gas storage reservoirs project. Section has no discussion of stress characterization.
- 5.3 Engineering Reservoir Characterization: Section does not specify what type of fluid characterization should be required. Additional needs include required tools to characterize reservoir. RP 1171 Section 8.6.1 Table 2 list key items to use. CSA Z341 - 7.2 defines vertical and lateral requirements for AOR and 7.3 list requirements on geologic studies, maps, fluid compatibility and observation wells. Further reservoir analysis from completion and production records is needed.
- 5.4 Containment Assurance of Reservoir Design: Additional design considerations for facilities such as flow erosion, hydrate potential, and disposal operations needed. Analysis needed for corrosive potential for various pressure range scenarios.
- 5.5 Environmental, Safety and Health Considerations in Design: May need to obtain API 51R[2] and API 76[3] as they identify "safeguards" for application is natural gas storage design. This may be covered by Act 238, Natural Gas Safety Act (MPSC).
- 5.6 Record Keeping: What kind of permitting is this section referring to? No mention of MIT's.
- 6.2 Wellhead Equipment and Valves: Based on specific locations (urban areas, proximity to homes or business, etc.) there may be a regulatory requirement to place an emergency shutdown valves. Does not address general drilling requirements for BOP design and diverter design if conditions warrant, BOP testing requirements and mud design/operations.
- 6.3 Well Casing: Based on geological conditions there may need to be a requirement to set a stronger casing.(I.E. H2S zones or flow zones). There may also be a need to set a mine string based on location. Each wellhead should be equipped to monitor all casing and annular pressures.

- 6.4 Casing Cementing Practice: Need to reference mill testing and transportation requirements and more detailed specifics for each casing string such as requirements for compression, tension, burst and collapse. Criteria for new versus used casing. Post cementing casing test requirements and Formation Integrity Test requirements.
- 6.5 Completion and Stimulation: General requirements need to address possible need for specific additives based on local conditions (example - H2S or CO2 environment. Requirements for compressive strength, water loss and zone of critical cement. Specific designs: Surface casing - cement to surface with procedure remediate if necessary; Intermediate and Production casing - cement top requirements. References include CSA Z341 Section 5.4
- 6.6 Well Remediation: Need to reference casing flow and tubing/packer configurations. Need to require casing test and cement evaluation prior to perforating and any stimulation. Pre-stimulation requirements such as surface equipment testing. During fracturing the monitoring of area wells and casing annulus during pumping and risk management plan if conditions indicate a potential breach.
- 6.7 Well Closure (Plugging and Abandonment): During the plugging operation each cement plug shall be set across hydrocarbon bearing zones and across the entire storage interval to prevent zonation. Each plug should be tagged to verify location. Storage interval plug should be pressure tested to at least 500 psi.
- 6.8 Environmental, Safety and Health: There are four API guidance's listed within this section. However most of this section is very broad terms and not specifics. Emergency response plan needs to be updated and submitted to regulatory agency.
- 6.9 Testing and Commissioning: what pressure would be required to test the production casing? The note describes one method, however there needs to be a standard regulation for this test.
- 6.10 Monitoring of Construction Activities: There is no mention of regulatory supervision or approval or jurisdiction of state agency over drilling process.
- 6.11 Record Keeping: This appears to be a comprehensive list of records to be maintained by the operator but does not provide any authority to the regulator regarding submission, review, or actionable items.
- 7.2 Testing and Commissioning: Does not address how baseline conditions will be established for existing storage fields.
- 7.3 Reservoir Integrity Monitoring: No discussion of leak detection systems or equipment. There are no provisions for metering the amount of product in or out. What is an acceptable about of discrepancy?
- 7.4 Mechanical Integrity Monitoring: No requirements for continuous monitoring or for recording of monitoring. No testing schedule or test criteria thresholds.

- 8.2 Risk Management: Suggest submitting operator's risk management plan to regulator for review, adjustment, and approval with periodic required updates depending on storage dynamics.
- 8.3 Data Collection and Integration: CSA Z341 provides definitions for common terms in risk management. Recommend defining risk management, hazard, hazard identification, hazard analysis, risk assessment and risk prevention and mitigation.
- 8.4 Threat and Hazard Identification and Analysis: Needs more specific data for inspecting for risks.
- 8.5 Risk Assessment: Risk assessment prioritizes risks to know what risk management directives should be followed. Process or methodology is good notwithstanding should and shall and regulatory verification. Discussion of hazard in API 1171 addresses only well, well site and reservoir. CSA Z341 (Annex B.3.1.1) addresses loss of life, injury or illness, harm to the environment, damage to property (adjacent as well) and economic loss…recommend inclusion.
- 8.6 Preventive and Mitigative (P&M) Measures: Section discussion is at a very high level. Recommend inclusion from CSA Z341 Annex B…3.1.2, 3.1.3, 3.2 and 4.
- 8.7 Periodic Review and Reassessment: What constitutes or is meant by a multi-disciplinary team is not specified or described. All new threats should be immediately added to risk management plan.
- 8.8 Record Keeping: Doe not contain a specific operator retention period and does not discuss submission to regulatory agency.
- 9.2 Integrity Demonstration, Verification and Monitoring Practice Overview: at a minimum the regulatory inspector should be notified when operating and maintenance practices occur on each well so that documentation of this activity can occur. How risk assessments are fed back into operations is not described.
- 9.3 Well Integrity Demonstration, Verification and Monitoring: How will 3rd party wells be verified if operator does not own these wells? There is nothing stating that a regulatory inspector must be present during tests of components
- 9.4 Reservoir Integrity: How would disputes between storage operator and third party operator if reservoir integrity became an issue? Regulator should be notified of any changes related to reservoir integrity and their effect on storage operations.
- 9.5 Gas Inventory Assessment: Section needs to specify appropriate and informative time intervals for gas inventory assessments. Does not specify reporting of inventory to regulatory agencies.
- 9.6 Flow and Pressure Monitoring: "Should" monitor flow rates and pressures of both wells and pipelines as potential reservoir or facility issue. Also "flow conditions" should be monitored for accelerating corrosion problems (wet versus dry, velocity/erosion) public should be site specific.

- 9.7 Integrity Non-Conformance and Response: "Should" document and maintain a program that lists anomalies and action taken. Continual program for addressing differences in actual versus design should be implemented. Integrity non-conformances are not specifically addressed in MPSC certification orders other than a typical requirement to notify MPSC staff of any abnormal operations or integrity issues that could impact public safety.
- 10.6 Emergency Preparedness/ Emergency Response: Emergency response plans were addressed in only a few of the MPSC certification cases. Not typically addressed in previous certification orders, but would likely be addressed in future MPSC certification cases.
- 11.4 Emergency Plans: Procedures for emergency plans have been addressed by the MPSC in a couple of cases, but are not typically addressed in MPSC certification orders. It's likely that going forward, the Commission may address emergency plans in certification orders.

The items listed above are examples only and do not reflect the entirety of the comments submitted to the Gas Storage Workgroup. The spreadsheet submitted with this document and entitled “Analysis of API RP’s 1170 and 1171” contains a complete listing of the comments submitted to the workgroup.

Analysis of API RP's for Regulatory Development		
API RP 1170	**Gap Analysis**	**Regulatory Analysis**
1Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage	Needs to incorporate the risk management, safety, security, procedures and training guidelines developed in RP 1171.	
1.1 Overview	Mentions only existing facilities: what about new facilities? Existing as of what date?	1. Nothing about assessing risks or defining appropriate strategies for mitigation and early identificaiton of possible problems. 2. States that anything in the RP is to be done "at the discretion of the user" which probably means the operator. Thus it is all optional!
1.2 Applicable Rules and Regulations	New wells need Class III permits. Real lack of regulatory knowledge. This RP can supercede any regulations pending a waiver. Regulatory requirement supercedes RP.	No discussion of the role of the UIC Program, Depending on regional location, disposal of the excess brine can be an issue. The RP is intended for recommended practices, not how natural gas storage within a solution mined salt cavern would be regulated. This section is missing the interagency coordination of federal, state and local regulatory authority. The RP lack's an regulatory framework of the creation of the cavern by solution mining to the abandoment of the cavern after natural gas storage has ceased. Recommend removing this language. This document is not reflective of any government regulation.
2 Normative References	Many important references available from the Solution Mining Research Institute (SMRI) that need to be considered. there is no references about the solution mining process. There should be included references about drilling, completing, creating the cavern, and abandoning the cavern. Other references for testing the integrity of the cavern should be included. Could also include API 65-2 "isolating potential flow zones during construction" Many other references beyond API and ASTM should be noted including IOGCC	
3 Terms, Definitions, Acronyms, and Abbreviations		
3.1 Terms and Definitions	could include an definition for aquifer because this is a type of natural gas storage.(that is presented in section 4.2 could also reference RP 1171.) 1. Interesting that caprock was defined here, but striken out in IOGCC Primer. We will need to adopt consistent terms. 2. Interesting that fracture gradient is specified only near the wellbore; it has also been applied to average formation pressure limits (like MOP) far from the wellbore where it is not a sufficient criterion for MOP. 3. Tectonic salt is a poor choice of terms; deformed salt would be more correct.	1. Should state that overburden includes caprock as part of the "confining zone." 2. Do we use MOP or MAOP? Aren't they synonymous in this context?
3.2 Acronyms and Abbreviations		

4 Overview of Underground Natural Gas Storage		
4.1 General	This section is missing a discussion about the use of compressed natural gas as a fuel for commercial and private cars and trucks. This will create more of a demand on natural gas year around.	Opening remarks do not resemble typical regulatory language and don’t provide agency with any reccomended practices or items of consideration. This section includes only background informaion that would need to be removed if this RP was an regulation. Does not provide any guidance for the regulator or operator.
4.2 Types of Underground Natural Gas Storage	Within the Aquifer reservoir storage case it does not include the discussion of an impermeable cap rock above the aquifer. The title should be Types of Underground Natural Gas Storage in Salt Formations. Without the "in Salt Formations" the RP is missing a discussion on the following types of natural gas storage:underground natural gas storage could also exist in converted mines (closer to the surface) and hard rock caverns in which a machine mined out for the purpose of storage of natural gas.	based on the type of underground natural gas storage field there will be different regulations required. The RP lacks information on different regulator requirements on natural gas storage based on the type of storage.
4.3 Natural Gas Storage in Salt Formations	solution mined salt has been also used for medical saline.	
4.4 Functional Integrity	Need to go beyond design, construction and operation to include exposure (i.e., known leakage or similar events, location relative to sensitive infrastructure, etc.) to include risk assessment and management up-front Shall instead of should	Section references sound engineering practices within document but gives no specifics. How would a regulatory agency determine the Functional Integrity of a cervern through every stage of development? There is no guidence of what engineering practices would be included during every statge of the cavern development. Regulations should specify specific needs for operation and also closure requirements.

4.5 Overview of Major Steps in the Development of Gas Storage Caverns	As part of the development, regulatory authorities should have the ability to require financial assurance of an operator. These funds would be used to decommission a site if the operator became insolvent or neglected responsibilities. The operator must acquiring all permits and approval from the appropriate agency who has regulatory approval for all steps of this process. Step 6 is missing drilling Class III well Well written, but should state what needs to be measured, monitored, and action plans dependent on those findings. Define how often intregrity of well is tested	Section describes the process of developing a storage cavern but gives no authority to regulate the activities mention and also gives little direction on how to evaluate the development process. register company with state and adhere to all regulations to be an owner of a solution mining well. Apply for a Class III permit. (this entails a number of different requirements from the company. These requirements are different depending on which state the project will occur.) This section does not include how to determine maximum pressure to inject water to create the cavern or the maximum natural gas injection. this section talks about a MIT for the cavern. there is no talk of what MIT test should be run. should reference section 10 and B.2.2. of this RP. this section talks about sonar survey, but no talks about what frequency this survey should be run. the regulatory agency should have a section about bonding, insurance requirements for natural gas storage cavern opperations. Regulations should specify measurement goals, thresholds, and action to be taken (by whom, when, and how reported and to whom). Periodic intregrity assessments should be within 5 years of each other.
5 Geological and Geomechanical Evaluation		
5.1 General Considerations	Conversion of existing bedded salt-solution mining caverns can be problematic. Lack of known extent of the caverns and roof of the caverns. What should a regulator look for when an operator is developing a project?	How would a regulatory agency determine the minimum required geological and geomechanical data that needs to be submitted at the beginning of the project through the whole process.

5.2 Site Selection Criteria	No mention of proximity to sensitive surface features. in section 5.2.1 there should be a consideration to existing natural gas pipelines to bring natural gas to the solution mined cavern. In section 5.2.3 needs to discuss looking at state and local regulations on water extraction for surface water and water wells. This section also does not discuss the use of an impoundment. in section 5.2.4 there could be other parties to use the brine water than Class II wells. There could be a salt company (i.e. Morton or Gargil Salt companies) or chemical companies to use this brine water. Also because this is not associated with oil and gas operation this could be used for water treatment and road deicing. 1. So- a third type of salt facility is introduced: tectonic. 2. The Note omits geomechanical properties of any faults, and determination of the in-situ stress state. 5.2.1 Site selection must also include current uses of the land surface (for example a gas storage cavern would not be developed in the middle of an urban area) and proximity of pipelines to transport gas from the caverns to the distribution system (but see 5.2.5). 5.2.3 Mere "availability" of raw water is insufficient as there may be state or local regulations governing such things as withdrawal rates for groundwater or surface water and the uses to which such water can be put.	Without any review criteria related to sensitive areas, regulatory agencies may not be able to review a proposed project on that basis. in section 5.2.3 there may need to register a water extraction permit depending on state regulations. In the state of Ohio if water is extracted more than 100,000 gallons per day then the company will need to register with the state as well as the extraction point. if an impoundment is going to be used then there are state regulations and agencies that will regulate this. These regulations will need to be followed. in section 5.2.4 there will be federal, state and local regulations depending on which type of brine disposal method used. in section 5.2.5 there needs to be minimum reporting requirements for amount of brine produced from the cavern, pressures, size of cavern, subsidence so that a database of this information is available. 1. Recommend deleting tectonic and going with domal (which is deformed by definition) and bedded (which is undeformed by definition). 2. Should state what else besides the formations should be characterized (i.e., faults and stress state). Elements of this standard can be enforeceable in that it can be required to submit this evaluation with at least minimal components of the RP Need to clearly define a set of parameters required by operator to provide regulator (different for bedded salt and domal salt). This section needs to be broken down into a list so there is no confusion between the operator and the regulator. A summary report would be the likely output from the evaluation.

5.3 Geologic Site Characterization	Additional buffer should be assessed on a site-by-site basis. Seems to be an adequate discussion of all the methods to obtain data but what amount of data is required for a project and what amount of responsibility of data interpretation falls on the regulator? In section 5.3.2.1 there are many areas where there is subsurface salt deposits and no oil and gas. This section fails to discuss this scenario. Also most older oil and gas well logs skipped the salt section. in section 5.3.2.2 is missing master thesis and doctoral dissertation review. in section 5.3.2.3.2 is used only for new well logging programs. Most historical logs will only have a few of the required logs. section 5.3.2.3 is missing regulatory requirements for submittal of logs. A huge amount of detail is here! 5.3.2.5 It is not clear that surface seismic surveys will be of much use in Michigan, where the salt is bedded, not domal, and where faulting od the salt is not usually considered to be a major concern. Similarly gravity surveys are likely to be of little use in Michigan. Much of this is left out of 1171.	Core data may not be essential in areas where solution mining has been occurring over a long period of time. Additionally, many successful SWDs were developed and currently operate without ever collecting new core data. However, this section represents the most comprehensive discussion thus far. in section 5.3.2.3.2 states that there should be minimum log suite of gamma ray, litho-density, neutron, dipole or full wave sonic and caliper logs but does state that there should be other logs run based on local geology. What log suite would the regulatory agency require for new Class III wells? Based on section 5.3.2.3 a requirement to submit any log ran to the regulatory agency. based on section 5.3.2.4 a requirement to submit any core data and cuttings to the regulatory agency. Section 5.3.2.4.3 is about handling core, this is a business decision. Other than the requirement of submitting core or samples and their specific regulation requirements. photographs or core should be required to be submitted to regulatory agency. in section 5.3.4.1 states that "exact methodology for solution mined salt cavern for natural gas storage, but it should be site specific." However this RP failes to provide a minimum regulatory requirement that the operator will have to follow or refer to federal and state regulations for solution mining projects. Section 5.3.4.3, what required geological maps would be required during the permitting process? Section 5.3.2.5.3 does not mention that there may be a permit for running seismic surveys or notification process. Need to refer to state regulations.(was placed is wrong section) Relationship between geologic uncertainty and risk (of what?) needs to be clarified 5.3.2.3.2 Well Logging Program should be run on any new well drilled for the project. At a minimum should include gamma ray, litho-density, neutron, dipole or full-wave sonic; and caliper logs. This is the minimum necessary to properly analyze salt for geomechanical properties.Not enforceable, federal or state standard should say that this should be must for minimum and must submit logs and analysis as it pertains to characterization. Is how to pick a salt cavern included in my regulatory rules? Further to the above, the geological characterization (including maps and possibly cross-sections) needs to be expanded to include the disposal formations, the fresh water formations, and oil formations on the flank of domes. Disposal formation extend needs to be mapped. Dome flank edge definition needs to be undertaken and all existing wells need to be evaluated with a regulator defined AOR.

5.4 Geomechanical Site Characterization	In-situ stress state in rock surrounding a salt dome or bedded salt requires specifying 5 values, not just vertical and one horizontal stress magnitude. 5.4 Geomechanical Site Characterization. Should perform a variety of tests to predict geomechanics including stress, strain, tension, compression, compressive stress and temperature of salt and nonsalt formations. Much of this is left out of 1171. Delineation of the edge of the salt in domal deposits is critical.	As a regulatory agency, what geomechanical test's will be required to be run on the salt formation? Need to measure stress state in rock surrounding salt to feed into the required models of cavern deformation during operation. 3D stress state, plus pore pressure and azimuthal orientation, are needed beyond the single horizontal stress component mentioned in the RP. 2. Measurements are always preferred over values pulled from literature or various (which?) databases. 3. All tests, analyses, and values of stress should be documented and transparent to the regulator. Not enforceable as a should statement, federal or state standard needs to say shall and incorporate elements noted in 5.4. There should be a report of this characterization that must be submitted and approved by agency. Are these techniques special to only salt caverns? Need to define the core studies for the project (one per facility) at minimum. Need to consider seismic reflection surveys to help accurately identify the edge of the salt domes.

5.5 Assessment of Cavern Stability and Geomechanical Performance	Specific casing depth discussed in Section 5.5.4 need to be tied to federal and state regulations for Class III wells. Section 5.5.6 talks nothing about a standard set maximum pressure equation, but rather discusses how it could be evaluated. This provides a regulator problems when determining what pressure is appropriate for the cavern to ensure integrity still occurs. section 5.57 is missing the requirement of long term subsidence monitoring. Gap is "Should" Statement Not mentioned in 1171	in section 5.5.5 there shall be a regulation of a casing seat so that added stresses to the cavern roof is minimal. Maximum storage pressure should have a standard equation that can be placed in statute. Section 5.5.7 should include a subsidence monitory program requirement. The program should include monitoring specific number of monuments over the life of the project and a reporting requirement of annual submittal for subsidence monitoring. State/federal rule would be enforceable as a "shall" statement with requirements to address the minimal key paramenters noted and assessed. Should have maximum pressure be under fracture gradient. Define frequency of subsidence surveys. Geomechanical analysis required to safe determine intercavern and flank distances based on predicted operating conditions or to determine suitable operating pressures for known distances.

6 Well Design	API 6.0 is a shall statement and performance standard that may be enforceable on the surface, but without design criteria specified in rule regarding hole, casing and well head design it would not. These criteria are addressed in the various API RP 6.2.2 through 7.6.9	Informational only.
6.1 General	Missing - cementing, testing No comments	No comments Informational only.

6.2 Hole Section Design	General comment is that proper annular spaces should be maintained to foster good cement jobs. Needs to include a reference to review and maintain state regulations for surface casing depth. It is believed that RP 6.2.2 and 6.2.3 appear enforceable as written if adopted as a federal or state rule. Which agencies are drilling and completing under ?	Note in surface casing section that if any unexpected USDWs are encountered after cementing surface string, another casing string must be run and cemented to surface. based on state regulations there is set standards for where surface casing is set for the Class III well as well as the Class II disposal well. There may also be spacing requirement between cemented casing strings. 6.2.4 would need to be "shall" statement in order to be enforceable and two intermediate casing strings across corrosive zones would be very good requirement for integrity. Likewise with API RP 6.2.5 must be a "shall" statement as the geomechanical analysis and distances of salt back and casing seat are key importance General drilling and completing procedures? Informational only.
6.3 Casing Design	No mention of testing casing strings and cement jobs prior to drilling out. within this section there is no description of testing the casing strings. Each string should be tested. There is also no description if used pipe is allowed for this operation. 6.3.2 It should be noted that individual states may have regulations establishing depth at which surface casing is to be set. It should be probably specified that used casing is not to be used in order to mimimize future problems due to corrosion/pitting or stress failure of used casing No comments Appropriate use of centralizers to ensure centralization of the casing string for successful cementing practices.	Without documented pressure tests of each string, future issues may be more difficult to resolve. there needs to be a standard to test each casing string to ensure there is no leaks. The RP states that the intermediate and productions casing on the lower portion should be welded, but there is no standard or testing procedure which would show the casing to have integrity prior to solution mining operations. There are state and federal regulations on testing casing for a Class III well. RP 6.3.3 to 6.3.6 are very complete but contain mixture of should and shall statements. Likely enforceable but state standards often reference other API or ASTM standards for casing No comments Informational only.

6.4 Wellhead Design	These are good recommendations, however there should be no regulatory requirement for the type of wellhead used other than the use of a BOP and able to withstand the permitted pressure. API 6.4.2 has some shall statements to make this substantially enforceable, the safety factors to be enforceable would have to be established as a shall with standard. API 6.4 Two used, one for solution mining and one for gas storage service. Shall be steel and sufficient strength to withstand the maximum operating pressure. Safety factors should be applied to design calculations to provide additional margin of mechanical strength. API 6.4.3 should allow injection of pressured raw water from surface, down the well, and return of the brine to surface for processing or disposal. Also designed to allow for injection of blanket into the production casing annulus. API 6.4.4 should be designed for gas injection and debrining operations. No comments/should be part of agency drilling? Wellhead needs to be properly configured from commencement of the project	API 6.4.3 would not be considered enforceable as adopted if it remains should statements. API 6.4.4 would not be considered enforceable as adopted if it remains should statements. API 6.4.2 has some shall statements to make this substantially enforceable, the safety factors to be enforceable would have to be established as a shall with standard. No comments/should be part of agency drilling? Should comply with API 6A and be rated for maximum operating and test pressures.

7 Drilling		
7.1 Rig and Equipment	section 7.1.1 states that a pad area shall be selected, however there is no mention of spill containment if a release occurs during the drilling operation. In section 7.1.3.1 states that a BOP needs to be used, which is important precaution. This section also talks about that the BOP needs to be tested, but there is no parameters on what pressure or how long the test needs to be completed and at what threshold a failure would occur. General Drilling requirements?	Ensuring the permit holder has the proper rig scheduled is not a duty of the regulator. This task generally falls to the drilling consultant. section 7.1.3.1 needs a standard BOP test, with high and low pressure thresholds determined by an equation or a specific value. Also there is no guidelines on how long the test should be performed and at what threshold would the test fail or pass (i.e. 5% loss). Section 7.1.4 should describe an regulation requiring each joint of casing to be inspected by the inspector and if a faulty joint is discovered then that joint could be rejected based on the faulty condition of the pipe. Also if the pipe is used then a testing procedure should occur so that integrity of the casing is verified. General drilling and completing procedures? Informational only.

7.2 Drilling Fluids	Adequate I agree with section 7.2.5 that there should be a plan developed before drilling on what would occur if circulation is lost. This plan should include which formations are typical to circulation loss and what will occur if circulation is lost while drilling. However would this be a regulatory reguirement for the project? the RP states should not shall. Saline drilling mud vs. conventional fresh water.	the regulatory acency inspector shall be notified prior to cementing operations. Saline water is used for caprock and injection formation. Informational only.

7.3 Drilling Guidelines	Adequate Within the geological evaluation of the site, there should be a determination if H2S has been present in any formation that will be proposed. If there has been H2S present within the township then monitoring equipment will be required. Other parts of this section are good recommended practices, but as a regulation would not be required but would be an operators decision. General Drilling requirements?	in section 7.3.2 H2S has historically been present in area within a formation that is encountered then it would be mandatory that H2S monitoring on site. General drilling and completing procedures? Informational only.

7.4 Logging	Adequate based on section 7.4.3 there needs to be a description of when should production casing logs are to be run. Would they be required initially and or at some schedule timeline developed by the regulating agency? 7.4.2 A temperature log is probably desireable but see 5.4.2 regarding cautions when using after-drilling temperature logs to detrermine undisturbed in-situ temperature. Cement bond logs should be required on all cemented strings to provide a baseline to compare against such logs as may be run in the future. Sosme consideraton shouldbe given as to whether the cement bond logs are run "under pressure". Should multi-finger caliber log be ran for all storage wells not just cavern?	in section 7.4.2 there should be a set minimum suite of logs required by law to be run and in specific situation there should be in statute that the regulatory agency could request operator to run a specific type of log based on local geology. There should be a requirement for submitting any log to the regulatory agency. Not enforceable as written, consider making a "shall" statement/rule. Cement bond log should be ran in storage wells after completion. Define what logs need to be run.
7.5 Casing Handling and Running	Adequate No comments	this is a business decision not a regulation to require specific protocols on casing handling and running. Not enforceable as written, consider making a "shall" statement/rule. No comments Informational only.

7.6 Cementing	No remedial cementing discussion. No testing of cemented strings prior to drill out. the casing shoe or float shoe should be tested. There should also be a blowout preventer used and should be tested as well. In section 7.6.4 it is important to condition the Annular space before cementing. In section 7.6.5.2 the preferred method of cementing should be the displacement method, however the operator may choose to use a different method. Regardless of what cementing method used there needs to be the an evaluation of the cement job and the top of the cement determination through a bond log. in section 7.6.11 states that multiple samples of the cement should be collected. This is a good practice to do. 7.6.3 It should be noted that individual states may have requirements about the types of cement that can be used. Why is this in more detail than 1171?	A cement Bond log should be required as well as the inspector to witness each cementing operation. there should be a requirement for testing cemented casing strings before drilling out the cement plug. The requirement of this test and the threshold for a pas or fail should be in statute. State and federal regulations will need to be referred to when drilling the Class III well. Based on the federal and state regulations for cementing each casing the operator should use the appropriate cementing method and hardware to ensure the minimum cementing requirement are reached. Appears that RP 7.6 may be enforceable if adopted since it is a shall RP, states may have more stringent. The RP does contain a recommendation in the compressive strench wait on cement time. Standard Cementing practices Needs to specify that cement should be either brought to surface on all strings or up into the next string, Remedial action for lack of cement to surface.

7. 7 Completion	Within section 7.7 states that fresh water should displace any drilling fluid in the wellbore. This is a good practice to do. However, would not be in a regulation. Within this section there should be a discussion of when the depth of each tubing string should be adjusted. There should be a reference to section 8.4.2. No comments	No comments Informational only.

8 Cavern Solution Mining	Gap is "Should" Statement API 8.2.2.2 The neck should extend below the the casing seat to cvern roof, the length should be equivelent to at least one-half the diameter of the predicted, fully developed cavern and should be confirmed with geomechanical modelling. API 8.2.2.4 The roof shall be developed with detailed planning, modeling and execution. After the roof is developed, blanket material shall be placed and monitored so as to protect the roof from uncontrolled solution mining. API 8.2.5 Solution mining model shall be used for the design and during development of, at least, the first cavern of a gas storage facility. The model shall be used to predict geometries of cavern shape during phases of development and used to determine if and when cavern workovers maybe required to shift the setting depts of the hanging strings, creating desired cavern shape.	No "should" For Roof: Yes, but work product documentation needs to be required? Appears that RP 7.6 may be enforceable if adopted since it is a shall RP Informational only.

8.1 General	No comments	No comments

8.2 Cavern Solution Mining Design	In section 8.2.2.2 states how important the cavern neck length is. This section also discusses the Nitrogen/Brine interface MIT, but should have a reference to section 10 and B.2.2. The Nitrogen/Brine interface MIT shall be run once the cavern is built to proposed size. There needs to be a pass/fail criterion set up. within section 8.2.5 states that cavern size needs to be measured by sonar surveys, but there is no discussion to frequency of surveys. in section 8.4.2.8 states that sonar surveys should be run without tubing present and could provide frequency, but should be up to the operator. No comments	In section 8.2.2.2 should have a requirement to verify the cavern neck length and be submitted on a form designated by the regulatory agency. there should be a regulation which states that a minimum blanket material shall be within the cavern and monitored(there needs to be a set time to verify the thickness of the blanket material. i.e. annually or quarterly). If there is a reduction of blanket material then operations should cease until the blanket material is sufficient to protect the roof of the cavern. within section 8.2.5 there needs to be a minimum required data submitted to the regulatory agency for the solution mining model, with forms to be filled out when data is updated. No comments Informational only.

8.3 Cavern Development Phases	As part of development, operator should have implemented a subsidence observation grid capable of detecting very small levels of subsidence. This grid should be visted and recorded annually to monitor for subsidence. No comments	within section 8.3.4 there needs to be a provision in law stating logs and any test run shall be submitted to regulatory agency. No comments Informational only.
8.4 Equipment	ESD equipment should be required at all times, not just during certain activities. the Emergency shutdowns equipment should be pressure rated above what the maximum expected pressures accounted during the development of the cavern. appears enforceable with API 5C3 reference. No comments	There should be required to have emergency shutdown equipment present on well. As well as a flow meter or electronic device to measure amount freshwater injected into the cavern and the amount of brine withdrawn from the cavern. No comments Informational only.

8.5 Instrumentation, Control, and Shut Down	Protection against overfilling and overpressing a storage caverns should be paramount. Once the MAOP has been exceeded, cavern integrity becomes questionable. API 8.5.2 Supervisory Control and Data Acquisition systems should be used cot monitor and control the solution mining process and shut cavern ESD valves when necessary to isolate the cavern. API 8.5.4 If plant pumps have capacity to increase pressure over MAOP, then over pressure protection systems shall be installed. Should there be audible alarm if not near residences?	The regulatory agency should have a schedule of record submittal for pressure monitoring that is occuring at the cavern. Pressures that exceed MAOP will indicate to the regulator that cavern integrity must be evaluated. there should be a requirement for a SCADA system and over pressure protection or something equivalent for the cavern. SCADA systems: Not enforceable as a "should" statement RP Overpressure Protection System: Yes enforceable if adopted. Brine/ Blanket Interface Logging: Yes. Returned Brine Salinity: Yes SCADA systems offer real time readings and great way to shut in caverns if there is an issue. Needs to specify the requirements.

8.6 Monitoring of the Cavern	Flow rates and injection/withdrawal volumes should be measured and recorded for reporting to regulatory agency. API 8.6 Monitoring of the cavern shall be conducted throughout cavern solution mining, debrining, and storage operations. API 8.6.3.3 Wireline logs, along with other methods shall be used throughout the solution mining process to monitor the depth of the blanket material. API 8.6.5 Operator shall measure the salinity of the water entering the cavern and the brine leaving the cavern. API 8.6.6 Solution mining procedures and facilities should include a corrosion monitoring program. Program should include wellbore casing program; influence of foreign direct-current sources; good resistivity; quality of cement jobs; corrosive nature of soil and formation fluids; potential oxygen sources; microbiology of injection water; oxygen levels of the injection water. API 8.6.7.1 Estimates of the total percentage of insolubles in the planned cavern volume should be determined from core samples and other reliable geological data. API 8.6.7.2 Cavern development SHALL be monitored for preferential mining by thorough/and periodic analysis of brine samples and periodic sonar surveys. API 8.6.7.3 Poor Mining Techniques can lead to salt fall. Blanket control shall be maintained at all times; Mining too long with tubing strings in one position can overenlarge a section and should be remodeled; Blanket and injection point can't be positioned too close; hanging string integrity SHALL be maintained by careful monitoring of flow, pressures, and salinity of the brine with any deviations immediately investigated; and water used for backwashing the brine string during debrining should not exceed the hanging string volume. API 8.6.7.4 if gas is encountered in salt or salt mass has known history of producing gas, a natural gas or inert gas pad should be used. More frequent wireline checks of the blanket depth should be initiated if gassy salt is encountered. Not involved in this process	there should be a cavern completion form or something similar that is required to be submitted to regulatory agency, which includes flow totals, pressure readings daily, percent of type of salt(NaCl, KCl, MgCl2) in the brine and submit monthly or quarterly. In section 8.6.7.4 there should be special permit conditions placed on caverns that are located in salt deposits which have a history of methane trapped in the salt. The special permit condition should include a provision to perform more blanket depth test to ensure there is enough protection agency dissolution of the roof. Yes enforceable, but several monitoring techniques are "should", a federal or state rule may need to specify minimum or requirement for the monitoring schema to be submitted and approved. Brine/ Blanket Interface Logging: Yes. Returned Brine Salinity: Yes. Corrosion Monitoring: Needs to be "shall" so not enforceable as is. API 8.6.7.2 is a should statement, with minor wording changes could be enforceable SHALL statement as administrative rule. Preferential Mining: Yes enforceable, but there is not specified methods or time. In the basic sense enforceable. Salt Falls: Not enforceable as "should" statement for hanging string volume, most of the RP is enforceable as "shall" statement upon adoption. Gassy Salt: No "should" Not involved in this process Need to specify frequency of casing inspections and sonar logging, including roof shots (different schedule than

8.7 Workovers during Solution Mining	Workover operations should be proposed and approved by regulator prior to implementing. when would a workover be required by the regulatory agency or by the operator? Section 8.7 states when it could be important to do a workover, but does not go into specific things that would trigger a workover required by the regulatory agency. API 8.7 contains should statements, with minor wording changes could be enforceable SHALL statement as administrative rule. Not involved in this process	there shall be a requirement for the inspector to be present once the tubing is removed from the well. The inspector shall inspect the tubing and have authority to require a joint to be replaced. There should be a notification to the regulatory agency prior to a workover. The RP states that a sonar survey, wellhead inspection and changes of any valves, and to perform a Nitrogen/Brine interface MIT. What would be the minimum requirement for a workover? Not involved in this process Informational only.

8.8 Workover to Configure for Gas Storage Service	MITs must be witnessed by regulatory authority and should be done anytime that operator believes integrity may have been jeopardized. In this section it states that once the cavern is solution mined to prescribed plan that a workover should occur. The regulatory agency needs to be informed and that a set of specific inspections should occur to determine if cavern is ready for Natural Gas Storage. what set of criterion or timeframe occurs to trigger a workover. API 8.8 contains should statements, with minor wording changes could be enforceable SHALL statement as administrative rule. Is the testing of the production casing a MIT?	Logs or tests capable of detecting roof-production casing seat integrity should be required prior to beginning operations and periodically after. If blanket material is not properly maintained or disturbed due to unplanned cavern development, the roof may be impacted. Within section 8.8.2 states that if tubing is to be reused for natural gas storage phase of the project then full body electromagnetic, ultrasonic inspection and thread and coupling inspection should occur. There needs to be a cut off protocol developed to ensure that each joint of tubing has integrity. the production casing needs to be inspected and wireline logs run to ensure that the production casing has adequate wall thickness. However there is no pass fail criterion discussed that would prohibit natural gas storage to occur due to defect to the production casing. in section 8.8.4 states that a sonar survey should be performed once the cavern is developed and about to be converted to gas storage to ensure that there are no structures within the cavern to impede storage volume or debrining of the cavern. The RP fail to determine what cavern shape a regulatory agency would prohibit gas storage in. in section 8.8.5 an inspector should witness and verify that an emergency shutdown valves and snubbing valves are in place. Should have a standard test to ensure they are working properly. based on section 8.8.6 each tubing string should have a Mill test Report that is submitted to the regulatory agency. In section 8.8.7 a MIT shall be performed on the cavern system. There are a number of different MIT's mentioned in section 10 and B.2.2. The regulatory agency shall pick a preferred method and have a provision in statute stating or other test considered effective by the regulatory agency.

8.9 Debrining the Cavern	API 8.9.2 A newly developed cavern should be connected to an existing gas storage cavern prior to the initial gas fill. API8.9.3 Care shall be taken to limit the maximum pressure to MOAP of the cavern. 8.9.4.1 General - care should be taken when receiving fluctuating gas to maintain proper wellhead pressures, constant flow is desireable, a sufficient cavern gas volume (cushion) is required to inject gas at varying flow rates and maintain a constant brine flow. PI 8.9.4.2 Operation procedures or installation of wellhead acceleerometers should be used to detect and correct oscillation. API 8.9.5 interface proximity can be calculated based on metered quantity of brine removed however should be verified periodically with an interface log. API 8.9.6 debrining piping shall be monitored to prevent overpressure or gas escape and should include: weep holes in the hanging string; hydrocarbon detectors; flow measurement to detect a rapid unexpected increase in flow; and pressure transmitters. API 8.10.1 existing caverns for other than gas storage, SHALL only be converted if they meet same criteria as those developed expressly for natural gas storage. API 8.10.2.1 a full geomechanical analyssi of the cavern should be completed. API 8.10.2.2 the shape SHALL be verified with open hole sonar survey. Irregular shape causes should be determined. API 8.10.2.3 a cavern with a large flat roof should be avoided. Too large should be determined by geomechanical modeling. API 8.10.2.5 evaluate proximity of converted cavern to to adjacent caverns and edge of salt should be evaluated No comments	in section 8.9.2 there needs to be a requirement for a high pressure and or low pressure shutoff. In section 8.9.6 there shall be a requirement for monitor devices on the tubing strings. In section 8.9.7 there shall be a requirement for well pressure control equipment used during workovers. API 8.9.2 contains should statements, with minor wording changes could be enforceable SHALL statement as administrative rule. Wellhead pressure: Not enforceable as is, needs structure perhaps on how this will be monitored and reported. API 8.9.4.1 is a performance recommendation, standard of practice but ambiguous from enforceability standpoint. Judgement. Oscillation of hanging string: Not enforceable- should statement would need to be converted to shall rule. Regular Interface Checks: Not enforceable if adopted as is, periodic verification would need to be quantified and not be "should". Monitoring devices: Yes enforceable, but may need defined minimum requirements? Trapped or Attic Gas: Care is not defined and really subjective, should be quantified perhaps, and well pressure control during work over must be a "shall" statement. Existing Cavern Conversions: May be enforceable but problematic since there may be some exceptions to be made for existing conditions if geomechanical analysis, modelling and integrity evaluation suggests some allowance for existing conditions not consistent with a new cavern will be safe. Adjacent Caverns and Edge of Salt: No "should" No comments

8.10 Existing Cavern Conversions	existing caverns shall meet the same standards a new permitted natural gas storage caverns. There is a list of criterion within section 8.10.1 which should be reviewed, however the RP lacks the minimum regulatory framework to show what standards need to be followed in a detailed way. Also the RF fails to describe how the regulatory agency would proceed in the permitting process if one or multiple criterion fail to meet the current standards. within the initial geological evaluation of the salt there needs to be a determination of the up section formations to see if they could trap natural gas if a roof collapse were to occur. API 8.10.1 existing caverns for other than gas storage, SHALL only be converted if they meet same criteria as those developed expressly for natural gas storage. API 8.10.2.1 a full geomechanical analysss of the cavern should be completed. API 8.10.2.2 the shape SHALL be verified with open hole sonar survey. Irregular shape causes should be determined. API 8.10.2.3 a cavern with a large flat roof should be avoided. Too large should be determined by geomechanical modeling. API 8.10.2.4 existing salt necks should extend a suffient distance below casing seat to prevent roof strains from affecting integrity of cemented casings. API 8.10.2.5 evaluate proximity of converted cavern to to adjacent caverns and edge of salt should be evaluated No comments	No comments Conversion plan should be approved by regulator.

8.11 Cavern Rewatering	No comments	No comments
8.12 Cavern Enlargement	Permit amendment for this? Control of the shape of the salt cavern and protection of the roof is critical to any cavern development for storage.	at the time in which a cavern needs to be enlarged or the operator wishes to enlarge a cavern then an additional permitting process needs to occur. The regulatory agency needs to set up protocols on approving or denying a cavern enlargement. Amendment? Enlargement plan should be approved by regulator.

9 Gas Storage Operations		
9.1 Minimum and Maximum Operating Limits	Need to state how min and max operating pressures are defined. Wouldn't someone besides the operator oversee rates and pressures? Pressure limits need to be established to prevent breakdown of the confining zones. Shut-off devices set at maximum allowable operational pressures.	Max and min operating pressures are generally set by the regulatory authority, not the regulated party. in section 9.1 it states the operator shall establish the maximum storage operating pressure. However the regulatory agency should have final approval of the operating pressure and inspect the facility to ensure that this pressure is not being exceeded. And state how they are verified and monitored for compliance during operations. Permitting by agency? Min and max pressures should be defined through core studies and geomechanical analysis, just by operator. Maximum allowable pressures set by the regulatory authority.

9.2 Equipment	API 9.2.1 Wellhead components exposed to raw water and brine flow during solution mining should not be used for storage service, particularly valves and well control equipment. API 9.2.2 each outlet shall have ESD valve installed at or very near the manual valves. These valves should be part of an ESD system that automatically shut in the cavern in the event of an emergency. API 9.2.3 each cavern should be equiped to measure flow into and out of the cavern. No comments	in section 9.2.2 is a good standard to have each outlet valve to have an ESD valve in case of an emergency. This is not enforceable as a "should" RP, but could be written as a shall requirement. If written as a shall, there could be an exception if components are shown to be safe and have integrity. ESD Equipment: Appears enforceable if adopted, second half could be stronger as a shall statement to ensure isolation of cavern in emergency. Flow Measurement Equipment: Not enforceable as a "should" statement, accurate measurements of flow into and out of cavern would desireable to ensure integrity and to understand origin of any issues/abnormalities in operation that occur. No comments Informational only.

9.3 Instrumentation, Control, and Shutdow	Automatic shut-down equipment should be tested regularly under the supervision of regulatory athority. it is important that there are audible or visual alarms in place that would go off in emergencies. There should also be emergency shut off for the operation if an emergency happens. In section 9.3.6 states that a fire and gas detector at the wellhead are important. the type of system should be set up by the operator. API 9.3.1 General cavern components should have control and shutdown devices installed and designed to safely shut in the cavern system in an emergency or when monitored parameters exceed allowable values. Monitoring equipment SHALL be used to detect and upset condition during debrining. Should include SCADA API 9.3.2; Alarms API 9.3.3; ESD system API 9.3.4; and OPP API 9.3.5. API 9.3.1 General cavern components should have control and shutdown devices installed and designed to safely shut in the cavern system in an emergency or when monitored parameters exceed allowable values. Monitoring equipment SHALL be used to detect and upset condition during debrining. Should include SCADA API 9.3.2; Alarms API 9.3.3; ESD system API 9.3.4; and OPP API 9.3.5. API 9.3.5.1 OPP sytem should be designed to prevent overpressure, auto shut in or isolation piping to block source of overpressure. Pressure monitoring at all times, even when shut in for long periods. API 9.3.5.2 the cemented annulus between production casing and next cemented string should be monitoried. Production casing annulus should be monitored. The wellhead piping pressure should be monitored. If there is a logging valve on wellhead, cavern pressure can also be monitored. If hanging string terminates in the brine, the pressure should be monitored to indicate tubing leak or break. API 9.3.6 appropriateness should be evaluated. No comments	Production casing annulus should be continuously monitored for pressure changes that may indicate and integrity issue. See below, subsections would need to be Shall and could be incorporated in overall requirement for monitoring, control, and shut down plan requirement which would be created, documented and submitted for approval, implemented and updated periodically. Not enforceable as "should" - this is a central safety concept that may deserve an enforceable rule that requires the systems noted. Overpressure Protection System: Not enforceable as "should". Pressure Monitoring Points: Not enforceable as "should". Fire and Gas Detection: Not enforceable as "should" No comments Informational only.

9.4 Inspection and Testing	Should be a much more comprehensive section the lays out notification, schedules for inspection, and required testing of all storage components. when would the regulatory agency require inspection or all safety protocols at the facility? API 9.4.1 Wellhead guages, transmitters, and safety devices should be tested and calibrated at least annually. Any malfunctioning equipment shall be repaired or replaced. API 9.4.2 references Section 10 for recommended practices for integrity monitoring programs. API 9.4.3 should be tested periodically to ensure critical operational data are accurate, alarms are properly calibrated and functional and safety related equipment is functioning properly. API 9.4.4 should be periodically tested to ensure they perform as intended. All components of system should be tested Scada system should be tested at least twice a year	Inspection and Testing: Not enforceable as "should". Integrity monitoring program: This RP would be enforceable if proposed as a requirement to develop, document and implement the program using adequate methods detailed in TABLE 1 and API 10 SCADA system checks: Not enforceable as "should". ESD system testing: Not enforceable as "should". Testing should be on schedule not periodically Testing plan and frequency should be defined.

9.5 Workovers	when would a regulatory agency require a workover during the gas storage stage? API 9.5.2.2 workover on a de-pressurized cavern. Careful observation of the brine level in the wellbore is required during workover as trapped or attic gas may be present and make way to surface. API 9.5.2.3 Snubbing rigs, equipment, and procedures shall be designed for the maximum gas pressure anticipated during workover. Prior to workover, gas pressure in the cavern should be reduced, if possible. No comments Proper well control equipment must be on the wellhead during any workovers and capable of allowing work under pressure.	This says requirement, but "careful observation" is not quantified or defined. First part of 9.5.2.3 is enforceable. The recommendation that cavern gas pressure should be reduced if possible prior to workover would not be enforceable and is really a best practice to help avoid larger emergencies. Workovers may need to be conducted when pressure can't be reduced, so it would be difficult or inappropriate to make this a shall rule without qualifiers. No comments Informational only.

9.6 Site Security and Safety	Based on the location of the operation would there be different safety protocol or would there be one standard for all operations? What would be the minimum site security required for each natural gas storage cavern? In section 9.6.10 states that there is a sign ID for the well, however there are minimum ID requirement set up by state regulations. API 9.6 is not enforceable as written if adopted but could be if stated as a rule that requires development, documentation and implementation of programs. Vague and should be updated at least annually No discussion of SSSVs or surface safety valves. All safety valves must be properly calibrated and function tested per API Specification 14A/ISO 10432.	Safety plan bare outline. Procedures should be part of the permitting process.

9.7 Operating Administration	require the development of a emergency response plan and blowout contingency plan for the facility. Include appropriate notifications based on state and federal regulations. In section 9.7.4 states that records should be kept until facility is decommissioned. However it does not state what would be submitted to the regulatory agency. Most of the criterion listed in 9.7.4 would be a requirement to submit to the regulatory agency. API 9.7.1 all operators shall have or evelop O&M procedures that should allow for the safe operation and maintenance of the wellhead and cavern to ensure integrity. Procedures of a comprehensive O&M manual should include: emergency procedures; mechanical integrity testing; ESD sytem testing; general workover procedures (specific workover procedures developed as needed); instrumentation testing and calibration; and periodic wellhead and wealhead valve inspections. API 9.7.2.1 General - Emergency response plans, operators should develop emergency response plans to provide for the safe control or shutdown of the storage facility, including cavers. Most plans should include: incident command structure; communication guidelines and communications; evacuation procedures; provide for safe shutdown; provide for safety of company personnel and the public; and emergency drills. API 9.7.2.2 Annual Review, the emergency response plan should be reviewed at least annually and tested for effectiveness using annual drills. API 9.7.3 The uncontrolled release of gas from a gas cavern should be addressed either in ERP or in a separate Blowout Contingency Plan. API 9.7.4 Records documenting cavern system development, operations, and maintanence should be maintained at least until the gas storage faciity is decommissioned. The should include: geomechanical studies; drilling and completion reports and records; solution mining data; workover reports; sonar survey reports; MIT reports; gas temperature and pressure; injection/withdrawal history; instrument inspection and testing; safety (ESD)	API 9.7.1 is enforceable for requirement of O&M procedures, especially if recommended list of procedures are set as a minimum for required sections of the procedures manual. API 9.7.2.1 is not enforceable as is. The RP is a "should" statement and recommended components contain "most" and "should" language. A few word changes can make this into enforceable rule. API 9.7.2.2 is not an enforceable RP as written due to "should" statement but is if incorporated as a rule stating review and drills "shall occur at least annually". API 9.7.3 is not an enforceable RP if adopted as it, "should" must be changed to "shall". API 9.7.4 is not enforceable as written. The RP is a "should" statement. Otherwise if this RP was a "shall" statement it could be an enforceable rule if incorporated into state statute or adopted federally. API 9.7.5.1 as written is not enforceable because it is a "should" statement. API 9.7.5.2 as written is not enforeceable. There is a way to combine with 9.7.5.1 to make one enforceable rule with changes to a shall statement. No complaints O&M procedures should be part of the permitting process.

10 Cavern Integrity Monitoring	only a few of these integrity monitoring methods are discussed any where else within the RP. There needs to be a greater detail on Cavern System, wellbore cavern, and wellhead integrity.	Informational only.
10.1 General	API 10.1 is not enforceable as written, but is a strong "shall" statement with flexability in creation of the monitoring methods. No comments	Should specify logic for determining frequency of test and action should value be above threshold (and how that is defined) Good list of different areas and types of intregrity testing Informational only.

10.2 Holistic and Comprehensive Approach	in section 10.2 states that there is no one best or preferred method to monitor cavern system integrity, however it should have a requirement that the operator shall demonstrate Cavern System, wellbore cavern, and wellhead integrity API 10.2 is not enforceable but is an excellent over-riding goal or tenant. How to make this RP a focus can likey be crafted into rule. Best method approved by state agency?	Pre-approved MIT testing? Informational only.
10.3 Integrity Monitoring Program	At a minimum there should be a base frequency for evaluating integrity of the system and accounting. API 10.3 appears to be enforceable RP if adopted Need a time frame	Should specify what actions are to be taken and by whom when a red-flag is identified Time frame? A plan needs to be approved by regulator and all logs and tests kept on file by operator and regulator.

10.4 Review of Integrity Monitoring Methods	API 10.4 appears enforceable as a shall statement, but uncertain of how to create an administrative record of this action without a requirement of showing this evaluation. Reviewed by state agency? RP 1170 mentions nitrogen-brine test, but no discussion of pass/fail criteria. Additionally, the freshwater-brine interface MIT developed by U.S. EPA and the Standard Annulus Pressure Test (SAPT) has applicability.	MIT's approved by agency pre-test?

11 Cavern Abandonment	there is no mention of restoration of the facility location. How would regulatory agency determine a site has been restored?	there needs to be a standard abandonment procedure set up for natural gas storage caverns. there shall also be an abandoment permit required for decommissioning and abandoning caverns. A standard of minimum requirements for cavern abandonments shall be included in statute with the ability to include specific permit conditions based on operations and the history of the particular cavern. The entire section is very weak from a regulatory point of view. An entire set of regulations needs to be prepared to deal with the monitoring period prior to plugging, the data to be collected, the frequency of collection, the analysis of that data to prove stabilization, the actual requirements to plug the wellbore or repair the wellbore so it can be plugged, and finally the site restoration.
11.1 Abandonment Objectives	API 11.1 is an objective and not enforceable or measurable. No comments	No comments Informational only.

11 .2 Abandonment Design	The plan to abandon a cavern should be submitted and approved by regulatory authority. There is no mention of permitting reguirements for abandoning the Class III well and cavern. The Reguirement for the operator to submitt a plugging procedure for approval by the regulatory agency. Not enforceable RP, but an abandonment plan rule could include at a minimum the perforce standard and minimum components tied to 11.3 to 11.8 No definte plan for abandoning? Lacks details for proper P&A. First plug needs a mechanical plug that creates a barrier and then stage-cemented to the surface.	Since all casing strings are cemented to surface, the wells should be plugged with a bridge plug set near the bottom of the production casing and plugged with cement to the surface. The bridge plug and bottom plug should be allowed to set and be pressure tested. this is just a set of guidelines to follow and would be enforcable in the current format. No definte plan set in stone Informational only.
11 .3 Removal of Stored Gas	Adequate what percentage of natural gas left in the cavern would be allowable? API 11.3 is enforceable as written if converted to a rule or adopted as requirement. No comments	No comments Informational only.

11 .4 Wellbore Integrity Test	Adequate API 11.4 is not an enforceable RP as written but could be if changed to "shall" statement. No comments	No comments Define the requirements if it doesn't pass the test. For extended shut-in monitoring periods, what is frequency of test and type of test (don't want to repressure cavern for MIT after letting it stabilize)
11 .5 Removal of Downhole Equipment	Adequate API 11.5 is not enforceable as written but could be as a "shall" rule. No comments	No comments Informational only.

11 .6 Production Casing Inspection	API 11.6 is not an enforceable RP as written but could be if changed to a "shall" rule. No comments	No comments Define the requirements if the inspection determines a problem. For extended shut-in monitoring periods, what is frequency of additional logging.
11 .7 Sonar Survey	API 11.7 is not an enforceable RP but a rule could state that survey shall be run, unless prevented by obstructions or other issues, and results submitted to agency. No comments Has limitations in bedded salt deposits due to rubble piles.	This final survey and interpretation should be kept in the regulatory agencies file for future review if development occurs in the area. No comments For extended shut-in monitoring periods, what is frequency of additional sonar surveys. What is the oldest survey permit before final closure of the cavern.

11 .8 Long-Term Monitoring	API 11.8 is not enforceable as written but could be if written as a "shall" rule. Why would facility not be plugged out? Subsidence monitoring needs to be addressed in greater detail. Annual subsidence monitoring is recommended with the establishment of monuments and survey loops tied into benchmarks.	Release of financial assurance instrument should not be required until the operator can demonstrate that the gas or stored hydrocarbon has been removed, the cavern is in a state of equilibrium, and it no longer poses a threat to the environment or human health and safety. there should be a regulation to perform and submit subsidence surveys of area around the cavern annually. Plug facility out? Monitor for subsistence? Define how long after a cavern is closed that surface monitoring should continued.
Annex A (informative) Open-hole Well Logs	within section 7.4.2 states that a gyroscopic log should be run, but this type of log is absent from this section. Also Caliper log, bond log are missing from this section as well.	Informational only.

A.1 General	No comments Does not address how often external mechanical integrity needs to be undertaken or does it discuss the combination of tool use to accurate evaluate mechanical integrity.	No comments Informational only.
A.2 Gamma-Ray (GR)	Can correlate GR with type logs	No comments Informational only.

A.3 Spectral Gamma-Ray	No comments	No comments Informational only.
A.4 Litho-density	No comments	No comments Informational only.

A.5 Compensated Neutron	No comments	No comments Informational only.
A.6 Borehole Compensated (BHC) Sonic	No comments	No comments Informational only.

A.7 Dipole or Array Sonic	No comments	No comments Informational only.
A.8 Check Shot Surveys	No comments	No comments Informational only.

A.9 Mud Log (Cuttings or Sample Log)	No comments	Great tool to identify lithology Informational only.
A.10 Temperature Logs	No comments Need to add Noise (Audio) logs. Need to discuss accepted industry standards for logging practices and requirements.	Good tool for compensating MIT data Informational only.

A.11 Multi-arm Caliper	No comments	Isn't this used on production casing as well? Informational only.
A.12 Resistivity	Common type of logging for lithology	No comments Informational only.

A.13 Spontaneous Potential (SP)	Not useful for high salinity zones?	No comments Informational only.
A.14 Borehole Imaging Logs	Recent issues with acoustic imaging not detecting casing issues	Recent issues with acoustic imaging not detecting casing issues from state agency example Informational only.

Annex B (normative) Integrity Monitoring Methods	No discussion on leak detection systems or equipment.	Informational only.
8.1 Cavern System Scope	What is the pre-determined amount of time?	Seems unreliable unless exact dimensions of cavern is known Informational only.

B.2 Wellbore Scope	Section B.2.2 should be referenced in the RP when Nitrogen/Brine interface MIT test is mentioned. There still needs to be a specific pass/fail criterion to be developed so that this MIT can be used. No comments	it should be a requirement to have a CBL run on at least on the production casing. Caliber or flux leakage logs seem to be most accurate testing cased holes Informational only.
8 .3 Cavern Scope	No comments	The operator should submit monument grid at the time of permitting the Class III application and submit annual measurements to the regulatory agency. Subsistence is very important item to watch Informational only.

8.4 Wellhead Scope	during the operational life to the well there should be inspections of the well head by the regulatory agency inspector and by the operator. No comments	No comments Informational only.
Bibliography	No comments	No comments

API RP 1171		

3 Definitions and abbreviations	The RP does not define the following terms: Maximum Acceptable Operating Pressure, Risk Management Plan, etc… The RP does not define the following terms: Maximum Acceptable Operating Pressure, Risk Management Plan, etc… The RP does not define the following terms: Maximum Acceptable Operating Pressure, Risk Management Plan, etc… The RP does not define a risk management or safety plan RP 1170 and 1171 should be combined for more complete definition list. In addition, CSA Z341 should be considered for additional definitions such as blow out preventer, cement bond log/evaluation, casing inspection log and/or combine all definitions found in other sections. Example - 1171 does include additional definitions such as maximum and minimum allowable pressure and risk management plan in sections 5.4.3 and 8.1 respectively. CSA Z341 defines maximum operating pressure in section 7.6.1 as discovery reservoir pressure or not to exceed 80% of confining layer (cap rock) The RP does not define the following terms: Maximum Acceptable Operating Pressure, Risk Management Plan, facility, etc. … Does not define groundwater, or freshwater, or aquifer, or regulating agency (Supervisor of Wells, etc.) May also need to define "storage project" to mean totality of system (reservoir, cap rock, wells, buffer, appurtenances, etc.), operator/permittee, i.e., bondable party.	The RP uses the term cap rock whereas a regulation might typically use the term confining zone. The RP uses the term cap rock whereas a regulation might typically use the term confining zone. The RP uses the term cap rock. So does RP 1170. This is the standard term and it should be retained for clarity. Terms like "bounding area" are too vague and non-geologic for IOGCC or PHMSA use. No permit details defined. Need consistency in terminology such as API RP uses cap rock and some regulatory bodies use the term confining zone. The RP uses the term cap rock whereas a regulation might typically use the term confining zone. It does provide for an opportunity to develop consistency but must look at other regulations to determine what the best term should be. Informational only. The RP uses the term cap rock whereas a regulation might typically use the term confining zone.

	The RP does not have any definitions relative to cavern storage The RP does not have any definitions relative to cavern storage The RP does not have any definitions relative to cavern storage. "Basal rock" is usually referred to as "underburden" as a counterpart to the standard term "overburden" which includes caprock. "Collector formation" should be renamed "caprock/top-seal sequence" to reflect current usage. "Minimum reservoir pressure" should be related to "working gas." RP 1170 and 1171 should be combined for more complete list. Informational discussion on benefits of gas storage, although informative it is not a regulatory issue. The RP does not have any definitions relative to cavern storage	Informational discussion on benefits of gas storage, although informative it is not a regulatory issue. Informational only. Lacks the regulatory knowledge needed.
	Informational discussion on benefits of gas storage. Although informative it is not a regulatory issue.	Section is informational only in providing general background on natural gas storage, such as need, history and technical aspects of storage. Informational discussion on benefits of gas storage. Although informative it is not a regulatory issue. Informational only.

4.2 Functions of underground natural gas storage	No comments OK General aspects of gas storage fundamentals are cited but nothing applicable to regulatory development. This section is descriptive rather than prescriptive. The steps and methods used to establish and monitor functional integrity are developed in later sections.	This information doesn't belong in a regulation. This background information does not need to be included as a regulation. No comments Includes a description of what components are contained in a gas storage operation. This is lacking in other sections. Does not provide any specific actions which would be required per a regulation. Too general to be used in a regulatory program. Informational only.
4.3 History of Underground Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs	No comments OK This Section (Section 5) of the RP is intended to apply only to operations conducted during commissioning until max pressure is reached or total capacity is reached according to paragraph 2, Section 1, of the RP which states "This RP applies to both existing and newly constructed facilities. However, Sections 5 and 7 apply exclusively to new facilities and facilities undergoing expansion." So assuming that nearly all existing gas storage fields are then beyond commissioning/total capacity stage, none of Section 5 is applicable to these existing fields. Figure #1 includes pressure tests for mature operating wells.	This information doesn't belong in a regulation. This background information does not need to be included as a regulation. No comments Since any requirements in this Section (Section 5) of the RP only pertain to new fields/facilities or to those fields undergoing "expansion", any requirements in this Section (5) would necessarily need to be repeated elsewhere to be considered applicable to existing storage fields. Informational only.

4.4 Geotechnical Aspects of Underground Natural Gas Storage	Section is void of reccomending how a regulator should evaluate geotechnical aspects of a storage project. The RP states that each potential natural gas storage resourvoir needs to be investigated to evaluate reservoir integrity, well integrity and fluid chemistry. However, there was no definative objective criteria to investigate . The RP is lacking detail's on how an geotechnical review of potential natural gas storage reservoir would be evaluated. The more correct term is geomechanical, not geotechnical. Vague about how to initially study reservoir. Interesting that "monitoring" is to include protection of potential integrity threats of third party drilling, hydrocarbon production, and mining. Also that less than idyllic conditions geologically can be managed by facility and operational controls. Seems to allude that "new" wells are capable of withstanding cyclic pressure and temperature swings, whereas existing wells require monitoring. If so, what is it about new wells that are designed differently from existing wells, if possible? The RP states"...a preliminary evaluation of the reservoir and confinement mechanisms SHALL be conducted, characterized, and presented in the form of geologic mapping and analysis." The next paragraphs indicate what "should" be used to formulate this "geological mapping and analysis." For regulatory purposes, the shear generality of the term "geologic mapping and analysis" is inadequate to define what is required to be investigated, analyzed, and reported. How would an agency know what	What is a regulator supposed to consider when looking at geotechnical data related to a storage reservoir? The document provides no guidence or reccommended practice regarding how to evaluate geotechnical aspects of a storage reservoir. More specific criteria for studying reservoir? Each reservoir requires site specific analysis. Scope of analysis includes investigating suitability of reservoir rock, cap rock, sealing mechanism below reservoir, and adjacent stratigraphy. Locate regional aquifers and any potential connection to reservoir. Quality of data needs to be evaluated to determine whether supplemental data is needed. Fluid/saturation analysis, faults, fractures, and anomalies need to be identified. Initial determination of competency of reservoir and cap rock. Characterization leads to delineating the extent needed for a buffer zone. A good variety of maps and figures should be created. This does not contain the details and specifications of what the minimum amount of information required for approval. It also does not include any regulatory oversight or approvals. Informational only.

5 Functional Integrity in the Design of Natural Gas Storage Reservoirs	the operator who would like to drill new wells for a natural gas storage field in deleted oil and gas reservoirs and aquifer reserviors would need to register with the state regulatory agency with proper bonding and insurance requirements based on state statute. A permit for a new well or conversion of an oil and gas well to a gas storage well would need to be issued. This Section of the RP expands upon geological work and seeks to predict behavior/response of the reservoir and adjacent areas from storage operations, complete review of existing wells, fluid chemistry and properties ascertained for compatibility and corrosion management. Further reservoir analysis from completion and production records, initial reservoir pressure determination, and pressure data throughout reservoir needs to be reviewed for inconsistencies.	Since the operative word throughout is "should", the RP does not actually require any actual specifics to be analyzed or identified that would be considered enforceable or for that matter to be submitted to an agency for review and/or approval. For regulatory purposes the components of API 51R(2) and API 76(3) which apply who should be included. Informational only.

5.2 Geological Reservoir Characterization	Section only mentions using existing data to do characterization of geologic reservoir. Should applicant be required to acquire no new data? The RP lacks information on what would be required geological information to submit at the time of permitting a new depleted natural gas storage reservoirs project. This section contains a lot of should, no shall statement. What is a appropriate vertical and areal buffer zone for the natural gas storage operation? would there be a set setback buffer created by statute or would it be site specific? The RP does not specify. Nothing about characterizing stress state is mentioned. Storage facilty should be checked for migration instead of using may. Each reservoir requires site specific analysis. Scope of analysis includes investigating suitability of reservoir rock, cap rock, sealing mechanism below reservoir, and adjacent stratigraphy. Locate regional aquifers and any potential connection to reservoir. Quality of data needs to be evaluated to determine whether supplemental data is needed. Fluid/saturation analysis. Faults, fractures, and anomalies need to be identified. Initial determination of competency of reservoir and cap rock. Characterization leads to delineating the extent needed for a buffer zone. Good variety of maps and figures should be created. Section 5.4.1 states "operator SHALL assess containment capability of the reservoir and wells…for	What are baseline standards for submittal of the characterization? Is there a minimum amount of data or analysis that shall be done? How should the reg agency evaluate the confining zone? How should reg agency deal with anomalous geologic features once discovered? Stress state in and above the reserfvoir must be characterized for reservoir and caprock performance to be predicted and modeled. Always have monitoring system for gas migration. The RP requires an evaluation of both the geological and engineering reviews to design the storage parameters and identify uncertainties. An assessment of the design for pressures and rates (both wells and reservoir) is also needed. This section speaks to connectivity with other porous zones and potential to mitigate. Section 5.4.4 addresses the necessity of assessing wellbore competency or containment assurance so as to determine the monitoring, integrity testing, or re-plugging. It also sets maximum injection pressure and the basis for maximum and minimum pressures. Maximum pressure threshold can be determined by various means including fracture gradient, initial pressures, cap rock K, and other means. The impacts of minimum pressure such as geo-mechanical stress, liquid influx, surface facility issues, etc., are mentioned. Supplemental data is desirable for aquifer storage including water pump testing and water levels. Additional design considerations for facilities such as flow erosion, hydrate potential, and disposal operations are mentioned. Analysis is needed for corrosive potential for various pressure range scenarios.

5.3 Engineering Reservoir Characterization	What type of fluid characterization should be required? Each well within the proposed storage field should have cement top above the caprock, which is verified with a bond log prior to conversion to a storage wells . No comments 1171 defines scope of sealing mechanism (confining zones), area of review and reservoir rock characterization. 1.) Additional needs include required tools to characterize reservoir. RP 1171 Section 8.6.1 Table 2 list key items to use. CSA Z341 - 7.2 defines vertical and lateral requirements for AOR and 7.3 list requirements on geologic studies, maps, fluid compatibility and observation wells. 2.) Lack of requirements for well spacing, proximity to ROW and site selection - see CSA Z341 Section 6 on required elements Expands upon geological work review and seeks to predict behavior/response of reservoir and adjacent areas from storage operations. Complete review of existing wells. Fluid chemistry and properties ascertained for compatibility and corrosion management. Further reservoir analysis from completion and production records. Initial reservoir pressure determination. Pressure data throughout reservoir needs to be reviewed for inconsistencies. Section 5.5.1 states "operator shall incorporate protection of surface water and groundwater resources into the design of storage facilities." An agency would not know what these design parameters incorporate without them being submitted and would not know that all groundwater or surface water	Is it the role of the regulator to ensure the operator produces a product with pipeline gas quality specs? No comments Use section in permitting, siting and area of review Agency may need to obtain API 51R[2] and API 76[3] as they identify "safeguards" for application of natural gas storage design. Informational only.

5.4 Containment Assurance of Reservoir Design	section mentions various design factors and areas of potential mechanical integrity loss but doesn't always provide information on how to deal with these potential pathways. Some sections include a mention to refer to other published API documents. How does this operate as a regulation? Blanket statements of "operator shall.." without any discussion of proper ways to accomplish task or how regulator will consider the requirement. How does this operate as a regulation? An evaluations of all wells which penetrate the caprock, intended storage reservoir, and basal rock. How would loss of functional integrity be addressed if another porous zone is indicated within the reservoir? If any of those wells need to be reopened, plugged backed and or replugged a permit by the regulatory agency would need to be acquired prior to that operation. Operator shall document the design basis for max reservoir pressure. Is faciily intregrity plan the same as overall safety plan?? 1171 provides scope for existing well review process in AOR analysis, reservoir properties evaluation (fluid chemistry, reservoir characterization - porosity, permeability and reservoir pressure analysis. Additional needs include defining AOR for well review process. Evaluation of both the geological and engineering reviews to design storage parameters and identify uncertainties. Assessment of design for pressures and rates (both wells and reservoir.) Speaks to connectivity with other porous zones and potential to mitigate. Section 5.4.4 addresses the necessity of	how would the regulatory agency set maximum and minimum allowable pressure for each storage well and the entire storage field? Regulations need to provide guidance for minimum specifications for MOP. Should have permit limiting pressure. Use section in permitting, siting and area of review Shall is used for records retention. Beyond general drilling, completion, and workover records that an agency typically requires to be submitted, this section indicates that historic production data, reservoir characterization records, reservoir design data, operational data, mineral rights, and the "facility integrity plan" be retained. The RP has no requirement to submit any records to a regulatory agency. Well integrity monitoring plan should be reviewed by and approved by the regulator.

5.5 Environmental, Safety and Health Considerations in Design	There are a minimum setback requirements for each well based on state regulations. Special permit conditions may apply to a well based on the well's proximity to other features (i.e. source water protection area, wetlands, water, etc.) t Operator "should" design for long-term viability and functional integrity…"? Vague about who to contact and what to do overall 1171 provides data acquisition scope for determining operational pressure integrity based on reservoir connectivity analysis, pressure analysis, existing well barrier analysis and facility design and integrity plan. Additional needs include verifying the quantity and quality of data to evaluate containment. See CSA Z341 7.2 & 7.3 for detailed list which includes assessment of regional and local fault zones and structural anomalies, delineation of storage zone, calculation of storage zone volume, results of core analysis and detailed structural and isopach mapping of storage zone. May need to obtain API 51R[2] and API 76[3] as they identify "safeguards" for application is natural gas storage design. This may be covered by Act 238, Natural Gas Safety Act (MPSC). Reference is given here to groundwater protection. Also monitoring of work site conditions for worker and public safety. The RP does not describe any kind of permitting process.	References to other published API documents will be of little use when trying to enforce or even educate operators on this "regulation". Change this to shall and specify performance-based criteria including KPIs. No mention of state regulation construction standards Use section in permitting, siting and area of review The RP does not describe any kind of permitting process. There is too much "operator shall determine" throughout section. Specific standards are needed for enforcement. Informational only.

5.6 Record Keeping	These records should be shared wholely with the regulatory agency. Additionally, monitoring and accounting records of gas storage inputs and withdrawals should be kept by the operator and submitted to the regulatory on a periodic basis. These records may be useful if integrity questions arise. What kind of permitting are they referring to? No mention of MIT's 1171 provides scope on design criteria to mitigate safety and environmental risk. Subsequent sections in 1171 will provide greater detail in design criteria and operational maintenance and monitoring Shall is used for records retention. Beyond general drilling, completion, and workover records that typically an agency such as OOGM requires to be submitted, this section indicates that historic production data, reservoir characterization records, reservoir design data, operational data, mineral rights, and the "facility integrity plan" be retained. This section identifies the basic requirements for WH fittings, pressure ratings, evaluation of existing equipment for proposed tests & workovers, and auto-vs-manual emergency shutdown. This section makes recommendations rather than requirements.	This section should include the provision of keeping and continually updating safety and risk management plans. These are just as important as the records mentioned in this section. Risk management plan should include estimated closure costs and be linked to financial assurance requirements. Within section 5.6 it is unclear what would be required submitted to the regulatory agency for the life of the storage wells and the facility as a whole. Facility records by regulator should be kept for at least a significant period of time after the facility is abandoned. Who would regulatory records go to? Federal level? This section does not provide for permitting or regulatory review. Several uses of "should" would have to be changed to "shall" for enforcement. Informational only.

6 Functional Integrity in the Design and Construction of Natural Gas Storage Wells	1171 list records needed for accurate and comprehensive design activities. Additional needs include list of required records - CSA Z341 sections 7.3.1 thru 7.4 list greater detail on records to be conducted and needed for evaluation. Section 10.1.6 list well record requirements for each storage well. This section does not provide specific hole sizes. The burst strengths refers to API 5C3. The RP states the operator should determine its own safety guidelines and indicates all factors may be dictated by applicable regulations.	Use in permitting and recordingkeeping There is no regulatory oversight, permitting, or formal review for applicability. The RP makes recommendations rather than requirements. Informational only.

		seems adequate
		based on specific locations (urban areas, proximity to homes or business, etc.) there may be a regulatory requirement to place an emergency shutdown valves.
		In section 6.2.3 all flanges, and well head assembly will be rated higher than the maximum allawable pressure. The well head shall be inspected and tested to ensure that the well head is not leaking pressure.
	No comments	
	General comment on RP 1171 - 1.)very limited discussion on well conversions (Section 5.4.4 - brief discussion). See CSA Z341 Section 5.8 on conversion requirements which includes inspection and testing criteria and recompletion requirements. 2.) 1171 does not address general drilling requirements for BOP design and diverter design if conditions warrant, BOP testing requirements and mud design/operations	Should automatic shutdown valves be required?
		Regulation needs to address Well conversions and general drilling requirements.
	WH components at minimum mechanical strength necessary for maximum anticipated pressures. Other components at equal or greater pressure. Valves for isolation, emergency shut down valves not required	No regulatory oversight is mentioned no permitting or formal review. Volumes in excess of calculated requirement "may" be used to circ./surface-should be "shall" be used. The cure time should be determined. The cement pumping design section has a lot of "should" and "may" that would have to be changed to "shall" or "will" in order to be enforceable. The use of other referenced API RP's on cementing provide adequate regulations for cementing.
	The cement design portion states slurry design should be based on appropriate parameters, but does not provide those parameters. The RP does not offer any specifics as to types of cement, or WOC times, or compressive strength. The RP indicates cement blends should meet design requirements; cement pumping design appears to be fairly thorough as a description of common industry practice. Cementing standards are referenced to other existing API RP's.	Informational only.
6.2 Wellhead Equipment and Valves	Recommend manual monthly testing of master valves and pipeline shut-off valves, not annually. Does not address redundant valving, such as a master shut-off or snubbing valve on the production casing so	

6.3 Well Casing	no standards for reconditioned casing (testing, etc) no standards for testing casing once installed in well. No mention of protection of deepest USDW or isolation of hydrocarbon zones from USDWs. Surface casing minimums are set by state statute. There may be different casing depth requirements set by state and fedural statutes for intermediate strings. There may need to be a mine string run due to the location of the well. Based on geological conditions there may need to be a requirement to set a stronger casing.(I.E. H2S zones or flow zones) Each state have own predetermined minimum depths for casing ? CSA Z341 4.3.1.1- requirement for H2S environment requiring material conforming to NACE MR0175 and 4.3.1.2 - connection requirement for outlets. In addition to require that each wellhead be equipped to monitor all casing and annular pressures conductor of sufficient size and grade, surface casings same but also protect GW, 2 or more strings needed, casings installed per manufacturers recommendations This section requires cement bond log "or other means" to determine placement and quality of cement	The loose standards presented here would be difficult to enforce as a regulator. Will not be a useful regulatory tool, only provides langauge that states intent of casing. Mixed usage of should and shall. No provisions for requirement of isolating unanticipated freshwater zones. Would probably be best to just refer well construction to the existing well construction rules enforced by oil/gas reg authority. Vague explanation of casing sizes and minimum depths. Regulation should reference appropriate API/NACE/ISO references for equipment design There is no regulatory oversight mentioned and no method for permitting, reporting or formal review. Minimum standards are not set. Recommendations exist rather than requirements. Informational only.

6.4 Casing Cementing Practice	no mention of annular space requirements which can foster a more adequate cement job. Does the operator have a duty to test a cemented casing string? Are there any requirements to condition the well bore prior to cementing? Where are the notification requirements to ensure regulatory agencies are able to witness and verify proper well construction? Cement quality section sends reader to another published document. API standards aren't available to non-members and come with a fee. Wells that are drilled or going to be converted to gas storage wells should have a CBL run to ensure cement top is above the caprock. The pressure test run on the production casing shall be witnessed by an inspector. State and federal regulations need to be referenced to determine minimum casing depth and cementing requirements for each casing string. However it is recommended for natural gas storage wells to have cement tops to atleast up into the next casing string if cement can not be ran to the surface(i.e. production cement top up to the casing seat of the intermediate casing.) This recommendation is for every casing string besides conductor and surface casing. No comments Need to reference mill testing and transportation requirements and more detailed specifics for each casing string such as requirements for compression, tension, burst and collapse. Criteria for new versus used casing. Post cementing casing test requirements and Formation Integrity Test requirements.	This standard has no specifications for how to deal with loss of circulation or remedial cementing operations. Requirements that mention cement volumes or height behind pipe are vague. This document provides very little in the way of what to consider when approving these well construction plans. This is a good overview of what to evaluate when designing a cementing program for a well to be used for natural gas storage. However in the practical sense of a regulation this section provides little direction of requirements for cementing of each casing string. These will be site specific and per well decisions and based on the current regulations of the regulatory agency. Cement should always be to surface on surface casing. Regulation should be more comprehensive to list design elements, casing running and testing elements There is no regulatory oversight mentioned, no permitting, reporting or formal review. No mention of reporting a well failure to any regulatory agency exists nor does it require actions which make it difficult to enforce. Cement bond log or temperature log required to define the top of cement of what strings (surface, intermediate, and production)? Remedial action for lack of cement to surface.

6.5 Completion and Stimulation	The stimulation and completion of the well needs to be filled out on an agency form and submitted to the regulatory agency . Any logging at the time should be submitted as well. No comments General requirements need to address possible need for specific additives based on local conditions (example - H2S or CO2 environment. Requirements for compressive strength, water loss and zone of critical cement. Specific designs: Surface casing - cement to surface with procedure remediate if necessary; Intermediate and Production casing - cement top requirements. References include CSA Z341 Section 5.4. ensure adequate pipe and Frm bond, cmt bond log after cure time, temp log only with in 12-24 hours after cmt, observe annulus during cmt job, MIT, This requires mechanical or cement plugs. There are no specific sizes or lengths mentioned. The RP uses "should" instead of "shall" for isolating a storage zone. It does not address volume extending additives, isolation of freshwater zones, hydrocarbon bearing zones, annular isolation of storage zone, nor does it verify the presence & location of plugs. The RP doesn't specify that plugging must prevent fluid migration.	No comments Regulation should be more comprehensive in cementing operations from design to evaluation There is no regulatory oversight mentioned. There is no method for permitting, reporting or formal review. The RP needs specific minimum plug size/length. Need to change “operator shall determine" to regulator must approve. Informational only.

6.6 Well Remediation	No mention of notifying regulatory agency when a well has lost MI. No mention of notification when placing a well back into service. When Mechanical Integrity has failed the regulatory agency needs to be notified. If remedial work is going to occur on a well, the operator shall submit a plan for approval. When the remedial work is approved the operator shall inform the inspector of the operation and the inspector shall evaluate the remedial work. State regulatory time frames for repairing or plugging well? Need to reference casing flow and tubing/packer configurations. Need to require casing test and cement evaluation prior to perforating and any stimulation. Pre-stimulation requirements such as surface equipment testing. During fracturing the monitoring of area wells and casing annulus during pumping and risk management plan if conditions indicate a potential breach. review all wells, correlate with baseline Frm log, use monitor wells, Well with compromised integrity to be addressed at operators convenience?? There are no specifics as how to achieve safety for the environment, site worker, or public safety. The RP does provide for an emergency response plan as mandatory.	Remedial actions related to a potential conduit should be planned, approved, and witnessed by the regulator. This section does not provide authority to regulatory agency to decide course of action for remedial activities or approve proposed activities. This does not function as a regulation. Overall this is oriented to the operator, not the regulatory agency. This section failes to discuss how a MI failure would be addressed by the reulatory agency. How a regulatory agency conduct enforcement against operator due to the MI failure at a particular well or facility is lacking within this RP. Should have determined time frame for repairing, temporarily abandoning or plugging well. Regulation needs to include specifics on casing testing and stimulation requirements. There is no regulatory oversight mentioned. There is no method for permitting, reporting or formal review. There are no specific standards. Informational only.

6.7 Well Closure (Plugging and Abandonment	Missing requirement for recovering and uncemented casing strings. Missing requirement for testing plugs before moving on. Missing requirement to get approval of plugging plan from regulator. during the plugging operation each cement plug shall be set across hydrocarbon bearing zones and across the entire storage interval to prevent zonation. Each plug shall be tagged. Operator should pressure test the storage inverval plug to 500 psi to ensure the storage inverval is issolated. Multiple should and shall statements. All shall if possible. Need definition on remediation response criteria and general remedial cementing criteria (CSA Z341 Section 5.4.13) long-term isolation, cements to API standards, proper length for isolation, plug in static conditions, no volume extending cement additives Pressure testing of production casing and/or tubing and packer prior to startup lacks specific minimum standards.	section refers reader to another API standard. Plugging should be in accordance with existing rules and regulations or be proposed and implemented with input from the regulator. State agency should approve plugging procedure. There is no regulatory oversight mentioned. There is no method for permitting, reporting or formal review. Define well plugging requirement such as location of plugs, type of plugs, length of cement plugs, tagging requirements, cement wait times.

6.8 Environmental, Safety and Health	There are four API guidance's listed within this section. However most of this section is very broad terms and not specifics. Emercency respnse plan needs to be updated and submitted to regulatory agency. Environmental impact review through state agency?? Need greater detail. See CSA Z341 Section 13 on design, cementing, testing and site restoration. save the environment as much as possible This section provides for oversight of all phases of operations, documentation of suitability of equipment and personnel; quality control; addressing problems, deviation from design or procedures, effect of collected data or problem resolution on established reservoir characterization. SSSV and surface safety valves properly calibrated and function tested per API Specifications 14A/ISO10432.	References to other published API documents regarding EHS practices do not offer much in the way of useful regulation. Mostly broad "should" statements regarding the operators duty to protect the surface water and groundwater. These statements will not make effective regulatory tools. State agency should approve plugging procedure. Regulation will require greater detail typical with many existing state regulations. There is no regulatory oversight mentioned. There is no method for permitting, reporting or formal review. Leaves too much to "operator" determination and “should" and "may" would have to be changed to shall. There are no time frames for action(s) to take place. This section would not be enforceable. Informational only.

6.9 Testing and Commissioning	This section includes no requirement for notification of regulatory agency upon scheduling a test. The integrity of the production string is paramount in the safe operation of storage wells and witnessing this test ensures that the well is capable of operating under pressure. Without verification of this sucessful test, what confidence does agency have? what pressure would be required to test the production casing ? The note describes one method, however there needs to be a standard regulation for this test. The inspector should inspect the casing that will be used and have authority to require another joint to be run. No comments General section covered in more detail in subsequent sections. "new" test before drilling out shoe, "existing" test above top of zone, tubing monitored by annulus tests Records of construction, completion and reworks of well shall be maintained for "life of facility," which is not defined. The list of information that should be included is quite detailed but does not include any forms nor submittal to a regulatory agency.	Are there any standards for retesting a wells MI? No comments No regulatory oversight mentioned no method for reporting or forms mentioned or suggested. Need to define the shoe test pressure, length of time, pass fail criteria, and reporting requirements. Need to define the logging submission requirements.

6.10 Monitoring of Construction Activities	No mention of regulatory supervision or approval. Does state agency has jurisdiction on well drilling process? Existing well commissioning should also have baseline cement evaluation and temp/noise in addition to casing test prior to commissioning. operator to ensure good job done It is notable that this section is ONLY intended to apply to operations during commissioning until max pressure or total capacity is reached. None of Section 7 is applicable to new and existing gas storage fields. Nothing in this section requires regulatory approval or reporting.	This doesn't resemble a regulation. There are no indications of what I should consider as a regulator or give any authority on approvals or notifications. Does state agency has jurisdiction on well drilling process? This section identifies requirements for verifying integrity of reservoir, wells, until maximum pressure and/or total capacity is achieved. It does not require regulatory oversight, approvals (permits etc.) or reports to be filled with any regulatory agency(s). Informational only.
6.11 Record Keeping	This appears to be a comprehensive list of records to be maintained by the opertor but does not provide any authority to the regulator regarding submission, review, or actionable items. As written, does not act as regulatory tool. majority of these items will be required to be submitted to the regulatory agency. Won't all fields have some sort of regulatory requirements soon? Need to reference appropriate training requirements, supervision and recordkeeping. maintain list of records for life of facility The RP recommends operators "should" identify certain baseline conditions such as annular pressures, gas compositions, liquid levels, base line logs, and ground water samples. It is not clear what "and/or mechanical condition evaluation" means.	These records should be provided to the regulator for analysis. Additionally, they should be provided as they are generated to allow for review during the process of storage field development. Is any time period of volume being kept and reported? The RP Recommends, not requires, documenting baseline pressure and volume conditions. Gas composition and fluid levels shall be documented. Baseline groundwater conditions need to be established near the wells and surface facility. The portions which are required with the SHALL are enforceable. The components of the specifics related to the SHALL statements also need to be specified and minimums established. This section would be very difficult to enforce. Informational only.

7 Functional Integrity of the Natural Gas Storage Reservoir and Wells Established and Demonstrated through Initial Attainment of Maximum Reservoir Pressure and Total Inventory	Section very detailed. Without requiring submittal of design parameters as determined by geological and engineering characterization, the regulatory agency(s) would not know what conditions may have been found, and what corrective actions employed. Since monitoring frequency is based on reservoir and well fluid loss potential and flow potential an agency would need to know the parameters and methodology for determining same. The reservoir monitoring and analysis techniques includes: reviewing pressure versus inventory; requiring key shut-in wells to obtain well data; well data from strategically located observation wells, monitoring data from nearby producing and disposal wells; the use of logging techniques for gas confirmation location. Other than an agency not being required to be informed of this data, and knowing that it exists; the program for monitoring seems adequate.	The material balance behavior of the reservoir at start up conditions shall be documented and monitored for unexpected conditions. Evaluation and corrections to be employed to avoid incidents and loss. The monitoring frequency is based on potential loss and flow. The reservoir pressure versus inventory relationships shall be monitored. Techniques to monitor relationships are: key observation wells; logging, gas composition analysis; fluid levels; reviewing performance of offset production and disposal wells; Monitoring applies to both storage zones and lateral offset zones and zones above cap rock, i.e., collector formations. Ultimately, the RP has “should" and "mays" instead of "shall" where "shall" is required to be enforceable and regulatory agency verification process is not identified. Informational only.

7.2 Testing and Commissioning	How can baseline conditions be established for existing storage fields? may require in certain areas water well testing for a specific radius (i.e. 1/4 of a mile) from the well. No comments Recommends documenting baseline pressure and volume conditions. Gas composition and fluid levels should be documented. Also baseline conditions should be established as to groundwater in vicinity.PR805(3) requires MIT @ max expected reservoir pressure. Before injecting fluid into a newly drilled well or previously existing well newly converted to an injection well to be utilized for gas storage, a permittee of an injection well shall provide for a test of the mechanical integrity of the casing, by a qualified person, utilizing either a pressure test at a bottom hole pressure of not less than the maximum expected operating pressure of the gas storage field or an equivalent test approved by the supervisor Various monitoring "should" be done but none is required to be submitted to the agency. The Risk Management plan sets the parameters of the monitoring program but the Risk Management Plan is not required to be submitted to the agency for review or comment.	Should provisions exist for gathering baseline data for existing storage operations? No comments For subsurface reservoir monitoring, pressure and temperature logging are used to detect abnormal flow or accumulation conditions. The sub-surface monitoring method(s) does include a "may" which would reduce the effectiveness and enforceability as a regulation. Pre-commissioning MIT needs to be documented and reported to regulator. Regulatory requirements for testing frequency and pass/fail criteria.

7.3 Reservoir Integrity Monitoring	How will operator provide assurance that inventory is accounted for? There are no provisions for metering the amount of product in or out. What is an acceptable about of discrepancy? If monitoring wells are detecting stored-gas, shouldn't inventory monitoring have detected this prior? There may be state regulations for production wells drilling within the protective buffer of a natural gas storage field. The use of shut in test should be witnessed by inspector. The use of monitor wells above storage formation as well as laterally (in production wells) from the field shall be used. However there is no discussion of remedial action for a breached storage reservoir if gas is migrating out. The RP also lacks notification requirement if the Reservoir looses Mechanical Integrity. How does operator check offset production? Previously covered in section 5.4.7, 6.7 and 6.9 Material balance behavior of the reservoir at start up conditions shall be documented and monitored for unexpected conditions. Evaluation and corrections to be employed to avoid incidents and loss. Monitoring frequency is based on potential loss and flow. Reservoir pressure versus inventory relationships shall be monitored. Techniques to monitor relationship are key observation wells, logging, gas composition	This section includes no requirement to notify agency that unexpected conditions have been detected. Monitoring well installation discussion uses "should" instead of "shall". Reporting of data? Regulation needs to place in appropriate regulatory structure This section requires all records to be kept regarding reservoir integrity, well testing, and basic regulatory reports over the life of the storage field/facility. It does require regulatory records to be filed. The list needs to be expanded to include all of the regulatory records required. Monitoring does not mean that much has to be documented or analyzed. As part of the integrity management plan, should there be a more formal process (periodic reports) to demonstrate inventory monitoring is occurring and indicating storage containment.

7.4 Mechanical Integrity Monitoring	No requirements for continuous monitoring or for recording of monitoring. What is schedule of testing? What thresholds indicate a leak? How often is inspection or monitoring dates? Need greater detail on P/V requirements not just semi-annual tests performed at low and high. Requirements to plot P/V during both injection and withdrawal to compare/analyze versus historical data. More detail on observation well requirements and offset well monitoring. For subsurface reservoir monitoring, pressure and temperature logging are used to detect abnormal flow or accumulation conditions.Part 615 does not require Risk Management Plans or formal assessment.PR805(3) requires MIT @ max expected reservoir pressure @ start-up. Operator" means the person authorized by contract or agreement by the owner to drill, operate, maintain, or plug a well. Operator does not include the operator of a natural gas storage field within the boundary of the natural gas storage field unless the natural gas storage field operator has either drilled, plugged, or replugged the well in question or has utilized the well for the injection or withdrawal of natural gas into or from the natural gas storage field The Risk Management Section does a good job assessing the Potential Threats and Consequences along with the Preventative and Mitigative Programs to address those specific threats. However, it does not address surface equipment which represents a significant risk to both public health and to the	As written, this standard would be difficult to use as a regulator. Mostly vague suggestions concerning mechanical integrity monitoring. Should instead of shall in most sentences regarding monitoring. Frequency of monitoring is not mentioned. There is no mention of notification of regulatory agency or other emergency management authorities upon discovery of a surface leak. Time frame for MIT's needed Regulation needs to set general P/V guidance The RP section excludes surface facilities, pipelines and compressors; other areas are thoroughly covered by listing potential threats and consequences, preventative and mitigative programs. A specific well integrity management plan that defines the acceptable activities (i.e. logging & pressure testing), frequency, schedule to confirm integrity and then monitor going forward, and requirements for follow-up actions (i.e. level of corrosion that requires a workover) needs to be approved by the regulator.

7.5 Record Keeping	No schedule for submittal of records. No mention of submitting records related to integrity issues or remedial actions taken following an issue. within the reporting document to the regulatory agency there needs to be a required section for any testing completed on the well due to a mechanical integrity issue. Permits involved with who exactly? Section covers pertinent integrity subjects for surface and subsurface monitoring. Need greater detail on monitoring requirements such as frequency on inspection and analysis of the following: 1) surface leaks 2) well injection/flow profile - rate/pressure 3) Observation well monitoring 4) annular pressure monitoring 5) subsurface inspections. To be in conjunction of risk management program. Essentially requires all records to be kept regarding reservoir integrity, well testing, and basic regulatory reports over the life of the storage field/facility. Part 615 does not require the operator to develop a risk management plan. R416, R 417 require logs related to drilling. Data is collected but it is not required to be sent to OOGM therefore it is not fully integrated into the regulatory framework. A potential gap is that drafting a comprehensive risk management plan for an existing field may be inadequate without having done the functional integrity design work (geological and engineering) that is apparently reserved only for new fields according to the RP.	No comments Regulation will need to require initial detailed monitoring protocol with risk management tree analysis for subsequent evaluations The operators shall develop Risk Management and implement the plan and institute monitoring for continuous improvement. Risk is defined as the consequence of a realized threat multiplied by the likelihood of its occurrence. This section does not provide the minimum standards or specifics to be enforceable or consistent. Nor, does it provide for a timeframe to repair or mitigate the issue. Define what data is required to be submitted to regulator, the forms to be used to provide the data, and schedule. Regulators need to maintain files at their district offices also.

8 Risk Management for Gas Storage Operations	Need more detail on type of data to be recorded for each function. Using performance data and other data to assess the threat and hazard interaction is good. No minimum standards are included.	table 1 and 2 are good overview of what risks are associated with natural gas storage. However the operator, should create a site specific preventive and mitigative measures. Regulator will need to determine what data needs to be submitted on a "predescribed" basis and what data will be retained by operator for life+ of project. The operator shall use all data to determine susceptibility to threats and hazards and address those threats and hazards. Performance data, operations and maintenance, engineering data, etc., shall be evaluated to assess the threat or hazard level. This section does not include any regulatory oversight. Informational only.
8.2 Risk Management	Operator should submit to regulatory agency their risk management plan for review. No comments Operators shall develop RM and implement plan and institute monitoring for continuous improvement. Risk is defined as the consequence of a realized threat multiplied by the likelihood of its occurrence. The regulatory agency needs to be included in the evaluation and identification of the threats and risks. Creating and following a Risk Management plan is essential to reducing risk to operate a facility without incident. No regulatory approvals, reviews or oversight are included.	Suggest submitting operator's risk management plan to regulator for review, adjustment, and approval with periodic required updates depending on storage dynamics No comments Overall concept of Risk Management Section 8 is very good except the "should' versus "shall" issue. No regulatory oversight is included. Informational only.

8.3 Data Collection and Integration	No comments CSA Z341 provides definitions for common terms in risk management. Recommend defining risk management, hazard, hazard identification, hazard analysis, risk assessment and risk prevention and mitigation. Operator shall use all data to determine susceptibility to threats and hazards and address threats and hazards interaction. Performance data, operations and maintenance, engineering data, etc., shall be evaluated to assess threat or hazard level. A gap may be that the regulatory agency may weigh the threats or risks ratings that have been identified (or not identified) differently than the operator and therefore desire different monitoring and verification than the operator. It would be appropriate for a regulatory agency to require and discuss with the operator the relative differences that may exist for high risk (priorities) or even possible oversights.	No comments This section is mainly focused on the methodology for reviewing the risk assessment and prioritizing the risks for mitigation. The RP states the operator "shall" evaluate the risk assessment but only "should" do so using certain protocols. The RP does not require the potential threats and consequences in Table 1 to actually be evaluated. No specific risks are required by the RP to be evaluated. It is important to note that this is where the "prioritization" for mitigative measures is set and does not involve regulatory input. Informational only.

8.4 Threat and Hazard Identification and Analysis	Need more specific date for inspecting for risks A hazard is a situation of condition that has the potential to cause loss, damage,…..A threat to storage functional integrity can be created by an encounter with a hazard or activation of a hazard…RP breaks down assessment into three categories: wells, reservoir, and surface. Some interrelationship between wells and reservoir threats/hazards necessarily overlaps. Reservoir threats break down into Third party drilling/operations, Geologic uncertainty, and reservoir fluid compatibility issues. Potential consequences of each threat are described very well. Overall concept of Risk Management Section 8 is very good except the "should' versus "shall" issue and regulatory agency verification process is unknown. No gaps noted. The list of potential P&M measures is thorough.	More than periodic evaluations of threats. Good list of potential risks Nothing in this section requires any P&M measure to actually be completed by the operator. It should state "shall" be done and indicate a date when it "shall" be done by to be enforceable. Informational only.

8.5 Risk Assessment	Company needs to independently have a risk assessment document. There also needs to be a dicussion of a bond for the facility if any leak, spill, or reclamation of the site. Still need more specific time intervals Discussion of hazard in API 1171 addresses only well, well site and reservoir. CSA Z341 (Annex B.3.1.1) addresses loss of life, injury or illness, harm to the environment, damage to property (adjacent as well) and economic loss…recommend inclusion. Under API 1171 8.4.2 recommend hazard analysis and review annually. Risk assessment prioritizes risks to know what risk management directives should be followed. Process or methodology is good notwithstanding should and shall and regulatory verification. There is no required submission to a regulatory agency(s).	Specify frequency and reporting requirements for risk assessments Still need more specific time intervals For regulatory purposes, the review/reassessment would need to be submitted to a regulatory agency for review and/or approval. Informational only.

8.6 Preventive and Mitigative (P&M) Measures	All employees shall be trained on preventive measures API section very high level. Recommend inclusion from CSA Z341 Annex B...3.1.2, 3.1.3, 3.2 and 4. Use these to expand API 8.5.2 a - f for more specificity. Under API 1171 8.5.2 phrase used.."familiar with"...recommend all reference to that be changed to strong working knowledge and/or demonstrated competency. P&M measure for drilling ascribes process should be in place for safety aspects by having a public and/or third party awareness. Gas sampling protocols suggested. Other treatment or monitoring programs are good notwithstanding "should' versus "shall". The RP does not set actual length of time to retain any records in this section.	Table 2 is a great outline of preventive and mitigative programs. A significant percentage of these will be required and submit documentation. However the way the section is set up this would be hard to regulate as is. All employees shall be trained on preventive measures. A time period (how long to retain records) would need to be set to be enforceable. An agency would need the ability to inspect records to verify compliance. A retention period should be spelled out. Informational only.

8.7 Periodic Review and Reassessment	what timeframe should the review of the risk management program occur? Every year, every 5 years, etc? Evaluation team should include a member of the regulatory agency. What constitutes or is meant by a multi-disciplinary team is not specified or described. All new threats should be immediately added to risk management Periodic review for effectiveness and to identify new risks shall be conducted but doesn't have a time frame. A distinction is made that performances measures should be developed to ensure effectiveness of risk management or if revisions are needed to P&M. The methodology and requirements contained in this section lack the definitive "shall" statements which would make the methodology and requirements enforceable. There are no minimum standards set with "Shall" statements. There is no regulatory review or approval process. It refers to Section 8 which identifies risks which also lacks the definitive "shall" statements to create enforceable minimum standards.	Specify frequency and reporting requirements for periodic reviews plus approval process for continued operation More specific time frame needed for review This Section provides a methodology and requirements for storage reservoir and well integrity demonstration, verification, and monitoring. Requirements using "shall" are enforceable. Requirements which use "should" or "may" may not be enforceable. There is no regulatory requirements to gain approvals for operator actions or plans. Informational only.

8.8 Record Keeping	Operator decides how long to keep their records. Where is risk management document kept on facility? Frequency left to operator. CSA not specific either. Consider annually Shall have a retention schedule but doesn't state what time frame should be kept or updated or what specific elements should be retained. It is not specific as to how the methods used are reviewed and approved by the regulatory agency(s). More specific requirements covering the issues contained in this section of API 1171 are needed. From the "NOTE" in this section, examples are given that are needed to maintain functional integrity including repairing and replacing of defective wellhead, valve, casing, or wellbore components, and temporary actions such as reducing operating pressure. Question - what criteria is used to evaluate the acceptability of a well bore component such as casing corrosion or cementing issues?	Specify retention periods. Vague policy overall with record retention. Risk management policy should be easily accessable to any employee. Acknowledges that different issues exist for maintaining integrity of reservoir and storage wells. A case by case risk assessment is needed to develop integrity demonstration, verification, and monitoring. This is an important aspect of gas storage safety and it doesn't require submittal to the agency for input, review, or approval and is therefore unenforceable. This section does not provide enforceable standards. Informational only.

9 Integrity Demonstration, Verification and Monitoring Practice	API is vague on timing. CSA Z341 throughout clearly states records to be kept for 15 years past facility decommissioning. API 1171 has identified the critical components of demonstrating well integrity. There are very clear requirements for what "shall" be done. There are “should" and "may' statements which lack a strong regulatory requirement. There is no mention of obtaining prior regulatory approval. Per the API RP, Integrity Demonstration, Verification, and Monitoring Practices are developed within the Risk Management Plan that is not required to be submitted for review or approval from a regulatory agency. Therefore, the sufficiency of the Plan is not addressed by the agency nor can the fulfillment of the integrity demonstration, verification, and monitoring practices be verified independently. Well integrity evaluation methods (downhole inspection, pressure testing, gas sampling) are listed but no specific timetable as to when and/or even if they are required. It seems the "out" may be to simply review the drilling records and not perform any actual testing. Each wellhead is only (shall) inspected annually for leaks. Same annual only requirement for valve testing. Requires monitoring of annular gas by measuring volume and pressure but does not state how often this shall be done.	The lack of set frequencies to conduct the recommended verification methodologies and the lack of defined minimum standards make this section un-enforceable. There is also no regulatory review or approvals required prior to and after the "tests" were conducted. Informational only.

9.2 Overview	at a minimum the regulatory inspector should be notified when operating and maintenance practices occur on each well so documentation of this activity can occur. How risk assessments are fed back into operations is not described. No comments Acknowledges different issues exist for maintaining integrity of reservoir and storage wells. Case by case risk assessment is needed to develop integrity demonstration, verification, and monitoring.Post initial start-up there are no requirements in Part 615 to demonstrate, verify, or monitor the integrity of the wells and reservoirs. Operators usually provide information when problems occur. Part 615 does not require the operator to conduct or report well and reservoir integrity tests or frequency of those tests. The operator should review new data, if gas is found in unexpected locations, or if there is third party activity. A timeframe needs to be defined. The strategic use of observation wells is important for potential pathway monitoring but no actual requirements exist in RP for determining placement (above cap rock, lateral in buffer zone, etc.) or to actually require them to exist. There is no actual requirement for gas composition comparison from annuli to upper zone since "should" is the operative word when in most cases it should be "shall".	Specify how management of change is to be conducted. Would like to see this as a must that operator uses risk management to maintain well intregrity RP states "should" review geological characterization based on gas location(s), pressure(s), review buffer zone (lateral and vertical components), monitor third party activity, use observation well data (in various zones/locations), evaluate gas samples from storage zone, annuli, and shallower zones. Again the lack of specific standards and time frames make this section hard to enforce. Well integrity management plan needs to be approved by the regulator. The regulator will need some guidelines as to what is the acceptable activities (i.e. logging & pressure testing), frequency, schedule to confirm integrity and then monitor going forward, and requirements for follow-up actions (i.e. level of corrosion that requires a workover).

9.3 Well Integrity Demonstration, Verification and Monitoring	Section lists many duties the operater shall perform and some schedules for performing them, but there is no provision for what must be done if shortfalls are discovered (i.e. report it, shut down, monitor and assess, etc). what frequency would an inspector perform a random inspection of each well? what type of monitoring would take place on plugged wells? How will operator evaluate mechanical intregrity of third party wells? API 1171 9.2.2 refers to sect 8 risk assessment. Part 615 does not require the operator to conduct integrity tests on wells, wells drilled thru the gas storage reservoirs, plugged wells, or wells within a safety zone. Wells which are drilled thru a gas storage reservoir are evaluated during the permitting process (R 301 and R413). The ability to monitor annular pressure is not required. OOGM staff conduct on-site inspections at least 1 time every 2 years. It appears for hydrocarbon reservoirs, the methodology suggested for monitoring reservoir integrity seems adequate. However these methods are not actually required by the RP. Submittal to a regulatory agency is not required. A different methodology used for aquifer storage is not required. The same issues of not involving a regulatory agency for approval exists. A specific standard for acceptable losses needs to be established. Frequency of visual checks for leaks at wellhead should be based depending upon risk and consequence.	How will storage operators inspect, pressure monitor, and sample gas of wells belonging to 3rd parties? The operator shall review mechanical integrity for each active well and each well that penetrates the storage reservoir in the buffer zone. How will 3rd party wells be verified if operator does not own these wells? operator shall perform visual test on wellhead, valves, and casing for operational efficency. These are termed mechanical intergrity tests for above ground components. Valves are open and shut to ensure valves are working properly.It states these shall be done annually by operator. However there is nothing stating about a regulatory inspector being present. How will operators inspect plugged wells within storage boundary? This is an important aspect of gas storage safety and the RP doesn't require submittal to agency for input, review, or approval and therefore makes this section unenforceable. In this section, only "should" is used, not "shall". No time frame for completion of any of the "should" requirements is stated. This section would not be enforceable due to the lack of specific standards and time frames. (1) It is highly unlikely that a storage operator will be able to monitor integrity of third party wells, especially if a well owner suspects no integrity across the storage zone and is recovering gas from the storage formation. A

9.4 Reservoir Integrity	Somewhere within this regulation should exist a provision for the reuglatory authority to require special permit conditions for wells proposed within the buffer zone or any area potentially impacted by the storage operation. How is the vertical and lateral buffer created? Is it based on a specific radius? Is all monitoring done via monitoring wells? CSA Z341 10.2.4.2.1 addresses mechanical testing/inspection within 5 years of commissioning. API 9.3.2 calls for inspecting wellhead assembly annually...CSA Z341 in 10.2.3 to inspect wellhead and casing vents every 3 months...more detailed language on visual inspection for leakage, corrosion, damage and any unsafe condition on the wellhead and assembly. API needs to reference manufacturer's recommended practice as well as their mention of operator's maintenance program. CSA Z341 in sections 4.2.2, 4.2.3, and 4.2.4 discusses material qualification categories, use of materials and non-complying materials....recommended this all be added to PHMSA. CSA Z341 calls for testing subsurface safety valves 2X per year where API stipulates "at least annually." See CSA Z341 10.2.1.2. API discusses corrosion lightly in 9.3.2. Augmenting with CSA Z341 8.3.1 a - e and 10.3.11 a - d or some derivative will bolster API. Additionally CSA Z341 8.3.2 a - f would give more clarity to the type of cathodic protection system to use. In CSA only impressed current systems may be used on well casings. In API 1171 it is not clear what to do about other wells within the buffer other than to monitor them for integrity issues. CSA is clear those wells (previously plugged, 3rd party etc must come into compliance to insure integrity is maintained. RP states "should" review geological characterization based on gas location(s), pressure(s), review buffer	Section expresses that P&A and completion designs of 3rd party wells should be based on reccommendations of storage operator. This should be based on the regulators requirements. If the storage operator has no right to influence activity occurring in the buffer zone, how could they be tasked with well and P&A design for another company? how would disputes between storage operator and third party operator if reservoir intergrity became an issue? Regulator should be notified of any changes related to reservoir integrity and their effect on sorage operations. Tricky with gas law of capture laws with migration of gas. Well plugging should be monitored by state agency. "Should" monitor flow rates and pressures of both wells and pipelines needs to be changed to shall as potential reservoir or facility issue. Also "flow conditions" shall be monitored for accelerating corrosion problems (wet versus dry, velocity/erosion). Any loss in reservoir integrity should be reported to the regulator.

9.5 Gas Inventory Assessment	The note before 9.5.5 states that semiannual surverys are often not effective in gas inventory assessment. Wellbore liquids as in produced water? API 1171 describes geological characterization in very general terms. CSA Z341 7.3.1 and 7.3.2 given more specifics about geologic studies and mapping. "Should" know reserves, base, and working gas at time of conversion, consider data quality (accuracy of gauges, shut-in pressures stabilization times), for hydrocarbon reservoirs, use methods of inventory assessment (high low storage level pressures, material balance studies, monitor shut-in well pressures, and monitoring key indicator wells(s) for pressure changes. Other methodologies listed for aquifer storage. Additional actions include measuring fuel, operations, losses, monitor liquid levels, and regularly update inventory-pressure relationship to design. Monitor the gas composition of both injected and withdrawn gas. There is no regulatory requirement to correct any non-conformance issues in this section. It state the operator "should" implement and maintain a plan to address non-conformance issues but does not mandate that they be done. Deviations, erosion, and non-conformance issues seem to all relate to the risk assessment but previously related issues regarding risk assessment are not required to be submitted to an agency for review, approval, or for general observations. This section lacks the specific minimum standards and time frames.	Specify appropriate and informative time intervals for gas inventory assessments. Would like to know if reporting of inventory would be sent out to any regulatory agency. Integrity Non-Conformance and Response is an important aspect of gas storage safety. As such, it should be required to be submitted to a regulatory agency for review or approval. Lacks the specific minimum standards and time frames which makes it hard to enforce. Variances and any plans to modify the operation to address the variances should be reported to the regulator.

9.6 Flow and Pressure Monitoring	No comments API is superior. Recommend API note concerning pressure gauge calibrations that manufacturer's specs be followed too. "Should" monitor flow rates and pressures of both wells and pipelines as potential reservoir or facility issue. Also "flow conditions" should be monitored for accelerating corrosion problems (wet versus dry, velocity/erosion)public should be site specific. There is no requirement to submit records to a regulatory authority. Record keeping is to be kept according to the "operator's procedure". This seems inadequate unless certain records are required to be submitted to an agency.	Would like all statements made to be mandatory A retention period would need to be set to be enforceable. The regulatory agency would need the ability to inspect to verify compliance with a retention period. Frequency of erosion monitoring should be part of the broader well integrity monitoring program.
9.7 Integrity Non-Conformance and Response	Mention of leaks? "Should" document and maintain a program that lists anomalies and action taken. Continual program for addressing differences in actual versus design should be implemented. Security measures for employees and	Leaks should be reported to agency. Need definition of response to non-conformance and procedure for notifying regulator.

9.8 Record Keeping	No comments Inspections, tests, patrols, analysis shall be documented. There is no requirement to submit plans and no regulatory review. There are no standards set forth as to populations, zoning etc. There is no mention of flow lines.	No comments There is no regulatory submittal, review or approval provided for. All technical data (well, geology, reservoir, core, inventory, flow data, facility construction information) should be kept for the life of the project and a defined period after the entire facility has been abandoned.
10 Site Security and Safety, Site Inspections, and Emergency Preparedness and Response	Fencing around each well head API 1171 9.8.2…retention. Only place I see in sections 8 - 11 that a specific time is given for retention…life of the facility. CSA calls for 15 years beyond facility decommissioning. I recommend somewhere in between…10 years. There is no requirement for submittal or review of access route by regulatory agency(s). There is no mention of access route planning or environmental issues, wetlands, footprint etc.	how would regulations change for site security for facilites located in different areas(i.e. urban area or non urban area)? There is no requirement of access route submittal or approval by a regulatory agency. There is no requirement to allow regulatory staff access. There is no required maintenance of access roads. Information only.

10.2 Site Security and Safety	Cattleguards around wells to protect from being hit? a little intense for well by well, but facility or hub positions could be beneficial There is no requirements for location data on signage. There is no requirement as to the size of sign or the visibility of the sign.	Some type of alarm for loss of pressure due to security issues is something to consider Signage is required and is enforceable. Information only.
10.3 Ingress and Egress	Ingress and Egress shall be required on permit application No comments API 1171 10.2.3 flammables..vague. CSA Z341 12.1 addresses fire prevention, combustible material control, wellhead enclosures, flaring, training and certification. CSA recommendations not as comprehensive on site security as API. be able to get to the well This provides good guidance as to the preparation of a safety inspection plan, but it lacks detail as to the frequency of inspections, assessment of hazards, reporting and documentation etc.	Roads should be maintained for easy access to facilty by personal or regulators. There is no regulatory requirements. This section provides guidance only. There are no specifics. There is no notification of hazards to a regulatory agency required. Information only.

10.4 Signage	state regulations have minimum requirements for well identification. Signs should be legible from at least 30 feet API requirement under 10.3.1…requires personnel and equipment access to a well…recommend 24/7. wellhead identification and facility This section requires the development of a plan with recommendations as to what should be in it. This section requires training by the company and a Blowout prevention plan, but overall lacks specifics with very few requirements.	Signs at compressor stations or facilty as a whole? There is no requirement as to what needs to be in a plan. There is no requirement for public or regulatory involvement. There is no submittal or approval required. Minimum information posted on sign needs to be specified by jurisdiction.
10.5 Site Inspections	Does outside agency or company get inspect on its own? ensure a good inspection There are no regulatory requirements. These are general comments.	How often should inspections be? Monthly? There are no regulatory requirement for, submittal, review or approval. Define what needs to be inspected, frequency, and documentation.

10.6 Emergency Preparedness / Emergency Response	Make sure to update local emergency contacts protocols and procedures and necessary contact information for immediate action The operator should be responsible for their training and internal procedures. Regulatory authority would be required in some areas such as worker safety (OSHA) and to protect the public health and the environment. In those cases the lack of specifically defined minimum standards and times frames is lacking.	at the time of permitting a storage facility a blowout contingency plan needs to be submitted to regulatory agency for review. Well blowout emergency well workover companies' numbers should be listed. This section is non-enforceable due to the use of the word "should". This section leaves the content and practices up to the company. Well blowout contingency plan required as part of the permitting process.

10.7 Cyber Security	Cyber security for SCADA systems? API very high level. CSA Z341 12.3 refers to CSA Z731…Emergency Preparedness and Response. Currently under review…very comprehensive document. API 1171 10.6.2…recommend training and drills be documented and always include civil authorities to the extent possible. general statement to keep safe This section does not include a regulatory agencies' role in the permitting of wells which would include well construction, reworks, remedial actions, etc. The operator's written procedures should identify minimum standards for well construction, etc. Approval of these minimum standards is a regulatory function. The lack of defined minimum standards and time frames would lead to inconsistencies between operators. Some well construction standards are included in other API recommended practices.	Could use more explanation for this overall. This section is non-enforceable due to use of word "should". It leaves content, time frames, and practices up to the company. Information only, but a developed plan would be part of the permitting.

11 Procedures and Training	Some of the operational and maintenance functions only apply to the operator. However, the references to Sections 7, 8 and 9 lead back to the lack of regulatory oversight and enforceable standards including defined time frames for accomplishing required actions.	Without defined minimum standards including time frames this part is not enforceable.
11.2 Procedures	States that the operator "should" integrate procedures with required regulatory practices. Follow pipeline regulatory or new regulations? operator developed procedures written in clear language, reviewed at operators preference The operators should have internal emergency plans, however, some portions of those plans need to be filed with regulatory agencies, emergency coordinators, and include well defined information so it can be put into effect immediately. The plans need to have regulatory review and oversight. This refers back to section 10 but the recommendations in section 10 do not require anything beyond the operator and only suggest integrating regulatory requirements.	Change to a requirement with appropriate oversight. Should have timed inveral for checking procedures. Standard information, submittal to emergency coordinators, and regulatory agencies is essential. The Section refers back to section 10 but those are recommendations not requirements so would not be enforceable. O&M procedures required as part of the permitting process.

11.3 Operations and Maintenance	What is meant by general procedures? Procedure review frequency in API 1171 is vague and left to operator. CSA Z341 10.1.8 addresses operating and maintenance procedure audits more specifically. have written set of operations protocols but modify as needed The operator's internal procedures do not need regulatory oversite. The procedures which address drilling, completion, servicing, reworking, remediation, and equipment specifications are regulatory functions. Those regulatory functions are not included in this section.	Don't like general procedures being used as this should be more specific. Recommendations are not enforceable. Minimum standards, processes, review, permitting, time frames, and regulatory oversight must be included in-order for this section to be enforceable. O&M procedures required as part of the permitting process.
11.4 Emergency Plans	No comments emergency plan familiarity done by operator The internal operating procedures and information exchange with service companies is not a regulatory issue. The pressure rating, type, location, testing of equipment is a regulatory issue which is generally addressed during a permitting or rework action approval by a regulatory agency. There is no regulatory oversite in this section.	No comments Without enforceable standards, regulatory review and approval processes (permitting) this section is not suitable as a regulation. ERP required as part of the permitting process.

11.5 Well Work	what specific test should be used to test blowout preventers? Regulatory agency needs to be notified prior to any well work occuring. Depending on the well work, the operator may need to recieve prior authorization through letter or permit from regulatory agency. Drilling and completing should be through state agency regulations. Refers back to 10.6 which is very high level. CSA Z341 refers to CSA Z341 which is a very comprehensive ERP planning document…in review. API 1171 11.4.2 refers to operator familiarity with emergency plans….recommend more stringent description such as working knowledge of or continually demonstrated competency. written procedures with respect to drilling, completion, servicing and well work-over operations. This does not include notification of a regulatory agency(s) when a problem is discovered.	State agency should approve intent to drill and completion reports required This only includes recommendations which are not enforceable. Internal procedures are not part of the regulatory requirements. There needs to be a formal process to request permission from a regulator to conduct well work and report the results (workovers, drilling, logging). Specific regulatory forms are required for this process.

11.6 Other Well Entry and Well Operation Procedures	No comments establish written procedures for wireline, slickline and logging operations, well testing and other well operations The operator should use sections 5, 7, 8 and 9 to develop frequency of review, data that is to be reviewed, and methods of determining what is normal. Those sections only make recommendations not requirements. This section lacks specific minimum standards to establish action levels. It also does not set minimum frequencies for review.	No comments There is no regulatory oversight, minimum standards, and set frequencies of reviews to make this section enforceable as a regulation. Same as above
11.7 Interaction with Control Room	No comments chain of command communication This section acts as guidance for the operator. It does not discuss entry of regulatory personnel.	No comments Regulatory agencies staff shall have un-restricted access. Much of this section is for internal operator procedures outside of regulatory control. Informational only.

11.8 Integrity and Risk Management	No comments should do randomized inspections and evaluate along the way Regulations may vary from agency to agency. There needs to be defined minimum requirements.	No comments This section is non-enforceable due to use of word "should" instead of "shall". It leaves the content and practices up to the company except where regulations exist. Regulator needs to review and approve the facility and well integrity plan.
11.9 Safety and Environmental Programs	No comments have written set of operations protocols but modify as needed This covers internal operator MOC. It does not address the need or method to address the MOC for regulatory requirements.	No comments It is not intended to be a regulation. Plans required as part of the permitting process.

11.10 Public Awareness and Damage Prevention	No comments Reference made to environmental and safety risks. CSA implies human health in numerous places. Recommend such as well. area training events should be implemented Much of this section is related to internal operator training program. It does not mention already established training requirements/certifications for State and Federal regulations (H2S Certification, HAZWOPER)	Encourage information to all public especially landowners on field site. This section did not mention current regulations. Informational only.
11.11 Management of Change (MOC)	need more detail in what would require a management of change for a given storage facility. General section is extremely vague. Should changes be advertised to regulatory agency? ensure proper route for implementation of rule/procedure change This section does not clearly identify what records need to be submitted to a regulatory agency(s) and at what frequency.	more details will need to be provided within this section as to what would require a MOC and what procedure would a regulatory agancy go through to approve such plan? Specify what MOC issues require a formal process, which do not, and why; specify regulator involvement in any changes that affect the sorage facility. All changes must be marked and shown during yearly agency review of regulatory agency This section requires record keeping but only as it pertains to "shall". In many places it states "should". The retention schedule is left to the discretion of the company. Informational only.

11.12 Training	Shall insteady of should statements MOC training and competency needs to be demonstrated. operator scheduled training for employees Procedures are not typically addressed in MPSC certification orders.	Most of these should be mandatory good requirements for training to prevent green employee in wrong place Informational only.
11.13 Records	No comments API 1171 11.12.1 addresses training but not frequency or record keeping. CSA Z341 addresses operator training records in 10.1.6. Add to training requirements operator is accountable to demonstrate individuals' competency. CSA refers to knowledge and skill vs familiar or aware. API 1171 11.12.4...phrases familiar with and aware of too vague...replace with strong working knowledge. for whatever time operator sees fit unless regulations exist otherwise Procedures are not typically addressed in MPSC certification orders.	Records should be retained for at least 5 years Requires record keeping but only as it pertains to shall and not "should". Retention schedule left at discretion of company Need to specify that all well records and operational information be kept for live of the project and for some period after the entire facility has been abandoned.

Permitting	General note for 1170 and 1171: Specify level of exposure of facilities: includes proximity to company or public assets, and also any previous safety or process issues at any given storage facility. Likelihood of occurrence (used to calcualte risk) is quite high for facilities that have experienced at least one event (e.g. Yaggi, Aliso Canyon, McDonald Island). Such facilities should be subject to a higher level of regulatory scrutiny than those that have not experienced failure events. API 11.13.3 retention left to operator in absence of regulatory requirement. CSA Z341....15 years past facility decommissioning.	A number of documents would be required to obtain approval for storage service from a regulator. Given this is a new process, with new rules and a new regulator, then a process would be required to officially permit the facility under the new rules and provide all the documents required in this regulation. Essentially proved that each facility is compliant with the new rules. Existing facilities should go through a re-permitting process to guarantee compliance.
1170 Environmental	A spill prevention and control plan should be required with some sort of spill retention system around each well (berm, wellhead sumps/pits, etc.).	