



Designation: G184 – 06 (Reapproved 2012)

Standard Practice for Evaluating and Qualifying Oil Field and Refinery Corrosion Inhibitors Using Rotating Cage¹

This standard is issued under the fixed designation G184; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ϵ) indicates an editorial change since the last revision or reapproval.

1. Scope

1.1 This practice covers a generally accepted procedure to use the rotating cage (RC) for evaluating corrosion inhibitors for oil field and refinery applications.

1.2 The values stated in SI units are to be regarded as standard. The values given in parentheses are for information only.

1.3 *This standard does not purport to address all of the safety concerns, if any, associated with its use. It is the responsibility of the user of this standard to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to use.*

2. Referenced Documents

2.1 *ASTM Standards:*²

[G1 Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens](#)

[G15 Terminology Relating to Corrosion and Corrosion Testing \(Withdrawn 2010\)](#)³

[G16 Guide for Applying Statistics to Analysis of Corrosion Data](#)

[G31 Guide for Laboratory Immersion Corrosion Testing of Metals](#)

[G46 Guide for Examination and Evaluation of Pitting Corrosion](#)

[G111 Guide for Corrosion Tests in High Temperature or High Pressure Environment, or Both](#)

[G170 Guide for Evaluating and Qualifying Oilfield and Refinery Corrosion Inhibitors in the Laboratory](#)

[D1141 Practice for the Preparation of Substitute Ocean Water](#)

¹ This practice is under the jurisdiction of ASTM Committee G01 on Corrosion of Metals and is the direct responsibility of Subcommittee G01.05 on Laboratory Corrosion Tests.

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² For referenced ASTM standards, visit the ASTM website, www.astm.org, or contact ASTM Customer Service at service@astm.org. For *Annual Book of ASTM Standards* volume information, refer to the standard's Document Summary page on the ASTM website.

³ The last approved version of this historical standard is referenced on www.astm.org.

D4410 Terminology for Fluvial Sediment

3. Terminology

3.1 The terminology used throughout shall be in accordance with Terminologies [G15](#) and [D4410](#) and Guide [G170](#).

4. Summary of Practice

4.1 This practice provides a method of evaluating corrosion inhibitor efficiency in a RC apparatus. The method uses a well-defined rotating specimen setup and mass loss measurements to determine corrosion rates in a laboratory apparatus. Measurements are made at a number of rotation rates to evaluate the inhibitor performance under increasingly severe hydrodynamic conditions.

5. Significance and Use

5.1 Selection of corrosion inhibitor for oil field and refinery applications involves qualification of corrosion inhibitors in the laboratory (see Guide [G170](#)). Field conditions should be simulated in the laboratory in a fast and cost-effective manner (**1**).⁴

5.2 Oil field corrosion inhibitors should provide protection over a range of flow conditions from stagnant to that found during typical production conditions. Not all inhibitors are equally effective over this range of conditions so it is important for a proper evaluation of inhibitors to test the inhibitors using a range of flow conditions.

5.3 The RC test system is relatively inexpensive and uses simple flat specimens that allow replicates to be run with each setup. (**2-13**).

5.4 In this practice, a general procedure is presented to obtain reproducible results using RC to simulate the effects of different types of coupon materials, inhibitor concentrations, oil, gas and brine compositions, temperature, pressure, and flow. Oil field fluids may often contain sand; however, this practice does not cover erosive effects that occur when sand is present.

⁴ The boldface numbers in parentheses refer to the list of references at the end of this standard.

6. Apparatus

6.1 Fig. 1 shows the schematic diagram of the RC system. An apparatus of suitable size (usually 7500 mL) is used, consisting of inlet and outlet ports, thermowell, temperature-regulating device, a heating device (mantle, hot plate, or bath), and a specimen support system.

6.1.1 The vessel (typically 150-mm diameter) is manufactured from an inert material. Cast acrylic and polytetrafluoroethylene (PTFE) have been used.

6.1.2 A PTFE base is fitted at the bottom of the container. At the center of the base, a hole is drilled into which the lower end of a stirring rod is placed. This arrangement stabilizes the stirrer and the coupons.

6.1.3 Typically, eight coupons (each of 75-mm length, 19-mm width, and 3-mm thickness, and a surface area of about 34.14 cm²) are supported between two PTFE disks (of 80-mm diameter) mounted 75 mm apart on the stirring rod (Fig. 2). Holes (10-mm diameter) about 15 mm away from the center are drilled in the top and bottom PTFE plates of the cage to increase the turbulence on the inside surface of the coupon (Fig. 3). This experimental setup can be used at temperatures up to 70°C and rotation speeds up to 1000 rpm.

6.2 The flow pattern varies, depending on the rotation speed, the volume of the container, and the fluids. The flow patterns are described in Guide G170.



NOTE 1—Gaps (typically 0.85 ± 0.01 cm) between the coupons introduce localized turbulence.

FIG. 2 Photo of Rotating Cage Containing Coupons

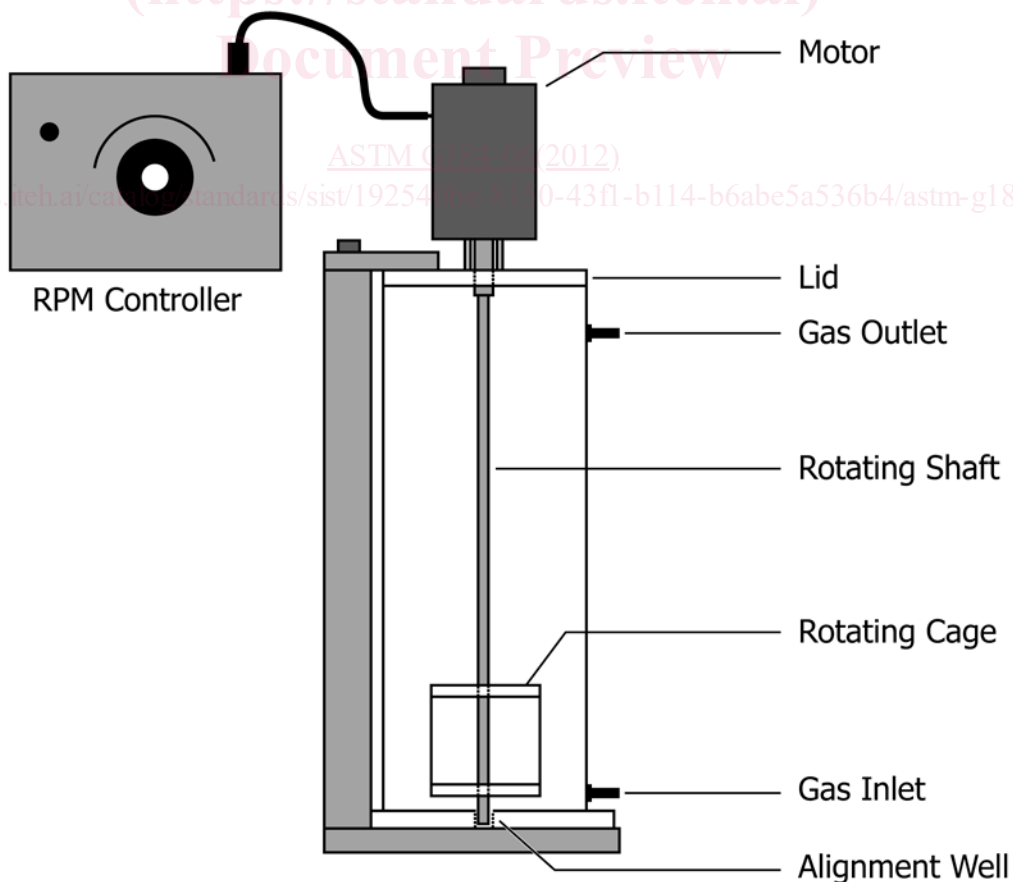
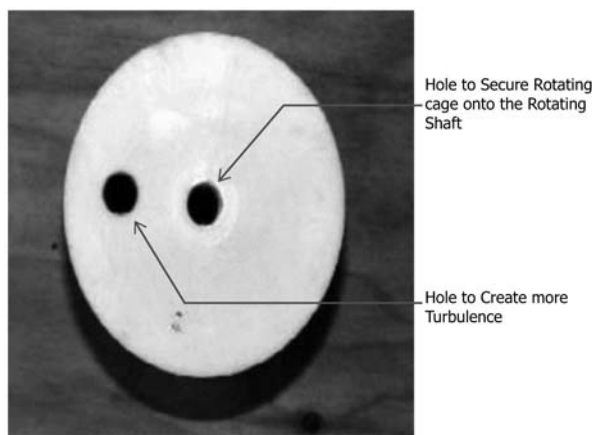


FIG. 1 Schematic Diagram of Rotating Cage



NOTE 1—Holes (typically 1.0 cm in diameter, and about 1.5 cm from the center) introduce localized turbulence.

FIG. 3 Photo of Rotating Cage (Top View)

6.3 Volume of solution to the surface area of the specimen has some effect on the corrosion rate and hence on the inhibitor efficiencies. The minimum solution volume to metal surface area is not less than 14 cm³ (11).

6.4 Open-beaker tests should not be used because of evaporation and contamination. Open-beaker test must not be conducted when H₂S (hydrogen sulfide) is used. In some tests, provisions might be needed for continuous flow or replenishment of the corrosive liquid, while simultaneously maintaining a controlled atmosphere.

6.5 For experiments above atmospheric pressure, a high-temperature, high-pressure rotating cage (HTHPRC) system and a vessel that can withstand high pressure without leakage shall be used.

6.6 The suggested components can be modified, simplified, or made more sophisticated to fit the needs of a particular investigation.

7. Materials

7.1 Methods for preparing specimens for tests and for removing specimens after the test are described in Practice G1. Standard laboratory glassware should be used for weighing and measuring reagent volumes.

7.2 The coupons shall be made of the material (such as carbon steel) for which the inhibitor is being evaluated. The coupon should have the same metallographic structure as that used in the service components. The coupons should be ground to a specified surface finish (such as 150-grit). The grinding should produce a reproducible surface finish, with no rust deposits, pits, or deep scratches. All sharp edges on the coupon should be ground. All loose dirt particles should be removed.

7.3 The coupons are rinsed with distilled water, degreased by immersing in acetone (or any suitable alcohol), ultrasonically cleaned for 1 min, and dried. The surface of the specimens should not be touched with bare hands. The specimens are weighed to the nearest 0.1 mg, the dimensions are measured to the nearest 0.1 mm, and the surface areas are calculated.

7.4 Freshly prepared specimens are installed in the rotating cage holder. If the test is not commenced within 4 h, the prepared coupons shall be stored in a desiccator to avoid pre-rusting.

8. Test Solutions

8.1 All solutions (oil and aqueous) should be obtained from the field for which the inhibitor is being evaluated. These are known as live solutions. It is important that live solutions do not already contain corrosion inhibitor. In the absence of live solutions, synthetic solutions should be used, the composition of which should be based on field water analysis. The composition of the solution should be determined and reported. Alternatively, standard brine (such as in Practice D1141) should be employed. The solutions should be prepared using analytical grade reagents and deionized water.

8.2 The solutions should be deoxygenated by passing nitrogen or any other inert gas for sufficient time to reduce the oxygen content below 5 ppb and preferably below 1 ppb in solution. The solution must be kept under deoxygenated conditions. The oxygen concentration in solution depends on the quality of gases used to purge the solution. Any leaks through the vessel, tubing, and joints shall be avoided.

8.3 The appropriate composition of gases is determined by the composition of gases in the field for which the inhibitor is evaluated. (**Warning**—Hydrogen sulfide (H₂S) and carbon dioxide (CO₂) are corrosive gases.) (**Warning**—H₂S is poisonous and should not be released into the atmosphere.) The appropriate composition of gas can be obtained by mixing H₂S and CO₂ streams from the standard laboratory gas supply. Nitrogen or other inert gases can be used as a diluent to obtain the required composition of corrosive gases. Alternatively, gas mixtures of the required compositions can be purchased from suppliers of industrial gases. The concentrations of impurities, particularly oxygen, shall be kept as low as possible with guidelines of below 5 ppb and preferably under 1 ppb oxygen in solution.

8.4 The solution pH before and after testing shall be measured, recorded and reported. The solution pH should be monitored regularly (at least once a day) during the test.

8.5 Inhibitor concentrations should be measured and reported in % mass/volume or parts per million (ppm). The method of injecting the inhibitor into the test solution should reflect the actual field application. Water-soluble inhibitors may be injected neat (as-received) into the test solution (aqueous phase). To avoid the errors associated with handling small volumes of solution, an inhibitor stock solution may be prepared by diluting the as-received chemical in an appropriate solvent. The type of solvent and the concentration of the stock solution depend on the characteristics of the inhibitor and on the specified test conditions.

8.6 Oil-soluble, water-dispersible inhibitor solutions are prepared by the following partition method. The required amounts of oil and brine are placed in the partitioning vessel (usually a separation funnel). The relative volumes of oil and aqueous phases should reflect the ratios of water and oil in the field for which the inhibitor is evaluated. If samples from the