UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-269/85-10, 50-270/85-10, and 50-287/85-10

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-269, 50-270, and 50-287 License Nos.: DPR-38, DPR-47, and DPR-55

Facility Name: Oconee 1, 2, and 3

Inspection Conducted: April 11 - May 13, 1985

Inspectors: C. W. Burger, for — 5/31/85
J. C. Bryant — Date Signed

C. W. Burger, for — 5/31/85
M. K. Sasser — Date Signed

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Approved by: H. C. Dance — 5/31/85
H. C. Dance, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 353 inspector-hours on site in the areas of operations, surveillance, plant trips, inspector followup items, quality assurance, and plant startup from refueling.

Results: Of the six areas inspected, no items of noncompliance or deviations were identified in five areas; one item of noncompliance was found in one area (Violation 270/85-10-01; Control rod position limits exceeded).

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *M. S. Tuckman, Station Manager
   *J. N. Pope, Superintendent of Operations
   T. Barr, Superintendent of Technical Services
   *T. Owen, Superintendent of Maintenance
   *R. Bond, Compliance Engineer
   *T. C. Matthews, Technical Specialist
   *R. Ledford, Quality Assurance (QA) Supervisor
   *R. Knoerr, Project Services Engineer

   Other licensee employees contacted included technicians, operators, mechanics, security force members, and staff engineers.

   *Attended exit interview

2. Exit Interview

   The inspection scope and findings were summarized on May 14, 1985, with those persons indicated in paragraph 1 above. The violation (para. 10), unresolved items (para. 14 and 15), and inspector followup items (para. 12 and 16) were discussed in more detail.

   The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Licensee Action on Previous Enforcement Matters

   Not inspected.

4. Inspector Followup Items

   (Closed) Inspector followup item 269, 270, 287/84-01-01; Review reactivity balance procedure retention. The reactivity balance procedures have been changed from operating procedures to periodic test procedures. Information is retained in the master file. The procedures files for all three units have all been reviewed by the residents.

5. Unresolved Items

   Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. Two unresolved items were identified during this inspection and are discussed in paragraphs 14 and 15.

6. Plant Operations

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records and equipment removal and restoration records were reviewed routinely. Interviews were conducted with plant operations, maintenance, chemistry, health physics and performance personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts, during week days and on weekends. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by Section 3.18 of the station directives. The complement of licensed personnel on each shift inspected met or exceeded the requirements of TS. Operators were responsive to plant annunciator alarms and were cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Turbine Building
Auxiliary Building
Units 1, 2, and 3 Electrical Equipment Rooms
Units 1, 2, and 3 Cable Spreading Rooms
Station Yard Zone within the Protected Area
Unit 2 Reactor Building

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

Unit 1 tripped from 100% power on April 11, 1985, due to a loose connection of an EHC circuit board. The reactor was taken critical at 7:46 p.m.. on April 11 and tripped from about 17% power at 10:46 p.m. due to fluctuations in turbine header pressure and was critical again at 12:57 a.m. on April 12. These trips are discussed in paragraph 9 of this report. The unit operated at essentially full power until 5:33 a.m. on April 25. Statalarm power was lost at 4:48 a.m., and an Alert declared at 5:12 a.m. The unit was critical at 3:57 a.m. on April 26, power was later reduced from 6% to subcritical to permit entry into the reactor building to open a letdown valve that would not open remotely. The reactor was again critical at 8:51 a.m. on April 26. This event is discussed in paragraph 12. The reactor operated at essentially full power for the remainder of the report period.

Unit 2 began the report period in refueling shutdown. The reactor was made critical at 12:10 a.m. on April 20, and startup physics testing was begun. Physics testing was completed and the reactor critical again about 1:00 p.m. on April 21. Power was increased to 20% and held there due to ICS problems. At 11:00 a.m. on April 22, the reactor received an anticipatory trip due to loss of MFWP A, the only feedwater pump in operation. This trip is discussed in paragraph 11. The reactor was critical at 1:27 p.m. and power

was increased to 72%. It was limited there due to apparent buildup of crud in one steam generator and consequent reactor cooling imbalance. Unit 2 tripped at 11:07 a.m. on April 26 due to a problem in the EHC system. This trip is discussed in paragraph 13. The reactor was made critical at 1:38 p.m. on April 26 and power increased to 72%, as limited by steam generator levels. On April 29, the reactor coolant pump 2B1 seal pressures began acting erratically. A subsequent evaluation led to the conclusion that the first stage seal had failed. After monitoring the seal instrumentation and through discussions with the seal manufacturer, Bingham, the licensee decided to continue operations until late June at which time an outage is scheduled for mechanical cleaning of the steam generators. The unit remained at 72% power through the end of the reporting period.

Unit 3 began the reporting period at 100% power, but with a failed reactor building cooling unit. The failed unit was repaired with the reactor at power. Repairs required longer than the seven days permitted by the TS; however, an emergency change to the TS permitted the increased time. The unit continued operation at 100% power throughout the reporting period.

7. Surveillance Testing

The surveillance tests listed below were reviewed and/or witnessed by the inspectors to verify procedural and performance adequacy.

The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work.

The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, tests were acceptable and systems restoration was completed.

Surveillances witnessed in whole or in part are as follows:

PT/2/A/015022C Valve functional testing during refueling outage

IP/O/A/3303A Control rod drive rod drop time test, Unit 2

Completed surveillances reviewed are as follows:

WR 90349C Annual fire protection test of warehouse #4 dry pipe valve system after performance test

WR 56842 Perform Keowee underground breaker interlock test on ACB 3 and ACB 4

WR 55055B Perform the capability test on the SSF 'DCSF' battery

WR 55053A Perform E/S system logic sub system 1, LPI channel 3 on line instrument calibration

WR 55314A RPS Channel A on line test

8. Maintenance Activities

Maintenance activities were reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Procedures and work requests were examined to verify proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met. Portions of several maintenance activities were observed in progress.

Completed maintenance work requests reviewed are as follows:

WR 50588 Repair penetration 1-N-N-5. Remove firewall 50 and repair with RTV foam

WR 50195D Leak repair on B core flood tank manway

WR 50109D Cell 8 in battery bank SY-2 reads SG 1.207. Bank average is 1.220. Install single cell charger.

WR 54326C Install 4 new front frames assemblies on Unit 1, 2, & 3 CRD breakers

9. Unit 1 Trip Due to Intercept Valves Closing

Unit 1 tripped from 100% power at 12:28 p.m. on April 11, 1985, when turbine intercept valves closed, without known cause, resulting in a reactor high pressure trip. Reactor systems responded normally to the trip and there was no ESF actuation.

The events recorder printout was essentially identical to that of the Unit 1 trip of January 22, 1985 (see Report No. 50-269/85-03). Following the trip in January, a cause was not found for the occurrence. Following the April 11 trip, a thorough examination of turbine control circuits was performed. A loose connection on a card was found which, when manipulated, signaled shaft overspeed and caused the intercept valves to close.

The reactor was started up at 7:46 p.m. on April 11 and the turbine placed on line at 10:31 p.m. At 10:46 p.m. fluctuations in turbine header pressure caused a swing in RCS pressure and the reactor tripped from low power. Dirty potentiometers were found in the integrated control system (ICS) which may have caused the fluctuation. The unit was restarted and was critical at 12:57 a.m. on April 12.

Following the first trip, main steam relief valves (MSRV) 2 and 10 failed to close until the secondary system pressure was reduced to about 900 psig and one of them continued to weep until pressure was reduced to 850 psig. MSRV's 2 and 10 were tested and relief points reset prior to reactor startup. Failure of MSRV's to reseat has been a subject in several recent reports and is being examined by the licensee (see Report No. 50-269/85-07).

No violations or deviations were identified.

10. Inadequate Shutdown Margin, Unit 2

On 4/21/85 at 10:55 p.m., the Unit 2 control room received a Statalarm indication of "rod withdrawal limits". The nuclear control operator (NCO) compared the control rod positions with the station procedure for the allowable limits for maintaining adequate shutdown margin and determined that the rods were in the unallowable region. At the time, reactor power was 15% and group 5 control rods were 70% withdrawn. Boron addition to the RCS was initiated immediately and the control rods were within limits by 12:55 a.m., 4/22/85. A subsequent evaluation by licensee Compliance staff determined the control rod position had violated TS 3.5.2.5, control rod positions.

Earlier during the day of this event, zero power physics testing (ZPPT) had been completed at which time the reactor was left at 0% power with control rod positions of group 5 at 0% withdrawn. That position, although not in violation of shutdown margin, was close to the limits. During the following power escalation to 15% the RCS was not adequately borated to withdraw control rods enough to remain within position limits. Operations estimated the limits were exceeded sometime after 5:00 p.m. on 4/21/85. The condition was not discovered during shift surveillances during and after shift turnover.

The basis for the TS limit is to maintain a shutdown margin of at least 1% delta k over k. The maintaining of adequate shutdown margin through control rod position is an operational and TS requirement. Failure to do so is cited as Violation 270/85-10-01, Exceeding control rod position limits.

11. Unit 2 Trip From 20% Power

Unit 2 tripped form 20% power on 4/22/85 at 11:00 a.m. The unit had started up from refueling outage and was maintaining power at 20% due to difficulties with the integrated control system (ICS). Only one main feedwater pump was operating at that power level. The event was initiated while attempting to close a breaker to place ventilation equipment in service. Upon closing the breaker, power to the 600V motor control center (MCC) feeding the breaker was lost. This led to the feedwater pump auxiliary oil pump, also fed from the MCC, being tripped resulting in low oil pressure on the feedwater pump turbine control system. The feedwater pump then tripped and the reactor tripped due to loss of feedwater (anticipatory trip).

Emergency feedwater responded as required to maintain steam generator water levels. There was no ESF actuation. All main steam relief valves reseated properly and other systems responded as designed.

Troubleshooting located a ground fault in the ventilation equipment breaker. Upon correction of the ground fault and completion of all post trip evaluations the reactor was made critical at 1:27 p.m. on April 22.

No violations or deviations were identified.

12. Unit 1 - Alert and Trip Due to Loss of Control Room Annunciators

Brief Description

An alert was declared at 5:12 a.m. on 4/25/85 in accordance with the Oconee emergency plan after most of the Unit 1 control room Statalarms were lost due to failure of an inverter power supply at 4:48 a.m. The plant remained stable and instrumentation and controls were operable. Loss of Statalarms was due to loss of the 1kx inverter, and its failure to transfer, which feeds the 120 Vac auxiliary panel board. Power was restored at 5:31 a.m. and at 5:33 a.m. the reactor tripped due to feedwater oscillations which occurred when feedwater began responding to a signal which was generated while power was off. All systems responded normally and there was no ESF actuation.

Cause of Failure

The event was initiated by an electrical short, apparently due to heat deterioration of insulation, in the 1kx inverter feeding the 120 Vac auxiliary panel board. This short interrupted power output from the inverter. There should have been an automatic switchover to the regulated AC power source; however, this did not occur because of broken solder joints which had apparently failed due to vibration.

As a result of the failure, Statalarms were received indicating trouble with the 120 Vac power supply. Also, most of the control room Statalarms were lost. This AC power also supplied the turbine driven feedwater pump speed controller gear unit.

Operator Action

An operator, followed by I&E personnel, was immediately dispatched to the equipment room to check the inverter, as required by procedure. Assessment of conditions revealed that all plant controls appeared to be functioning properly, indicating the reactor to be in a stable condition. Concurrent with assessment of plant conditions, operations personnel reviewed the appropriate emergency procedures to determine what action was required. At 5:12 a.m. it was determined that, in accordance with the emergency plan, loss of most or all alarms in the control room required declaration of an alert. The alert was declared, site assembly procedures initiated, and notification of required local, state, and NRC officials begun.

Upon loss of the annunciators, the operations supervisor decided not to trip the reactor since there was positive indication that the reactor was stable and to trip the unit would introduce a transient during the time when vital annunciators were not available.

Personnel in the equipment room determined immediately that an indicator light was illuminated, indicating that power had switched to the regulated power supply. It developed later that this light was powered by a logic circuit and only indicated that the demand for automatic switchover had been made. After finding no reason for ac power failing to reach the annunciator panel, it was discovered that the transfer to regulated ac had not actually occurred, despite the indication that it had. Upon checking with the control room, operators transferred power with the manual switch at 5:31 a.m., restoring the Statalarms.

Restoration of power initiated oscillations in the ICS, primarily in the feedwater system. In an attempt to control feedwater swings, the RO took manual control of feedwater. However, FWP A tripped seconds later and FWP B tripped at 5:33 a.m., resulting in an anticipatory reactor trip. All systems responded normally to the trip with the exception of two main steam relief valves which did not reseat at the proper pressure. One did not reseat completely until pressure was reduced to 825 psig.

Main feedwater was restored at 6:02 a.m. and the alert was terminated at 6:33 a.m. on April 25.

Cause of Feedwater Trip

Apparently, during the 40 minutes without power a small, normal feedwater oscillation caused a demand from the ICS for increased FW flow, causing the FW valves to begin opening. Decreased pressure drop across the FW valves gives a signal to the FW pumps to increase speed. However due to loss of power to the FWP turbine gear controller, the FW pumps were unable to respond. When power was restored, FW pumps accelerated in response to the then fully open FW valves. Six seconds after power was restored the operators began a series of operations of taking FW pumps and valves to manual, back to auto, and the pumps back to auto in an attempt to balance the system. Valve operation is considerably faster than pump response, which contributed to failure of their efforts.

FWP A tripped on high discharge pressure one minute and six seconds after power was restored, and a reactor power runback began. FWP B tripped 19 seconds later followed immediately by a reactor anticipatory trip.

Summary

Modifications to the inverters to improve circuit reliability have been completed on Units 1 & 3 and partially completed on Unit 2. These modifications will be completed as soon as possible. The inverter transfer indicating light will be modified to give a positive indication of transfer.

Operator training concentrates primarily on safety related issues. The operators receive considerable training on loss of instrumentation in the classroom and on the simulator. Training covers power supplies to basic equipment including power supplied by inverters. Power supplied by inverters is covered, dealing mainly with basic equipment such as integrated control system and electro-hydraulic control system, but is not detailed about specific parts of the basic equipment. Training does not deal in detail on what to do with losses of power to specific parts of non safety related equipment. The licensee is reviewing the incident to determine possible changes to the training program, particularly concerning the ICS and EHC systems, to improve response to similar events.

Procedures are being reviewed by the licensee to determine what changes might be made which could have been of assistance in handling the loss of inverter power or similar events.

In retrospect, the trip probably could have been avoided by taking the FWP turbines and FW valves to manual mode before restoration of power, balancing the error signal, then returning to automatic and restoring power. However, there are 12 auto/manual stations for the ICS. Normally, only one at a time is placed in manual in order to maintain plant stability. To attempt to balance all of these prior to restoring inverter power would have extended the time without power prohibitively. The licensee will evaluate procedures to determine possible improvements.

The inspectors determined that the operating staff was responsive and performed correctly under the conditions given. The safety valves which were slow to reseat are scheduled for rework on the next cold shutdown of sufficient duration.

No violations or deviations were identified. The resident inspectors will followup on licensee actions described above: namely, (1) modifications to inverters, (2) changes to operator training program, and (3) procedure changes. This is identified as an inspector followup item 269, 270, 287/85-10-02, Modifications and training concerning power loss.

13. Unit 2 Trip Due to Electro Hydraulic Control (EHC) System

Unit 2 tripped at 11:07 a.m. on April 26, 1985 due to a problem in the EHC system. At the time of the trip, maintenance personnel were working in the EHC cabinet. Cause of the malfunction has not been determined and no questionable component has been identified; however, the turbine received a load imbalance signal and began running back to reduce steam flow. Since there was no actual imbalance, reduction of steam flow created an imbalance. The reactor began power reduction but apparently could not reduce rapidly enough and tripped on high pressure. All systems responded normally and there was no ESF actuation.

The inspectors witnessed the startup to criticality which was achieved at 1:38 p.m. on April 26. The generator was placed on line at 5:29 p.m.

No violations or deviations were identified.

14. Unit 2 Reactor Coolant Pump (RCP) Stud Procurement

On April 24, 1985, the resident inspectors were informed by the licensee of an evaluation in progress of apparent document discrepancies which involved procurement of Unit 2 RCP studs from Rocky Mountain Nuclear (RMN) of Salt Lake City, Utah. The studs had been installed and the unit was then at 60% power following a refueling shutdown. On April 25, the residents and a Region II inspector reviewed QA documents, discussed the situation with site QA personnel, and discussed it with corporate licensing personnel in order to evaluate the engineering decision which permitted continued reactor operation. The inspectors concurred with the licensee's decision to continue operation. The sequence of events and basis for the decision are described in the following text.

On March 15, 1985 the licensee's general office (GO) vendor QA section gave Oconee site QA a verbal release for use of the RCP studs, even though a documentation problem had been identified in which the QA paperwork did not contain the required statement that weld repair had not been done on the stud material. The GO had verified with RMN that the documents could be corrected. Oconee QA then released the studs for installation after completion of visual and UT examination.

On April 17, GO QA notified site QA of a continuing problem with RMN paperwork and that a GO vendor audit of RMN would be conducted on April 22. Since the problem appeared to be in the paperwork, the QA department decided not to delay Unit 2 startup.

Based on results of the April 22 audit of RMN the QA department initiated a nonconforming item report (NCIR) to document what then appeared to be problems of a more serious nature than previously thought. The NCIR stated that the RCP studs were not supplied in accordance with ASME section III based on the following:

1. Material for the studs was procured by RMN from an unapproved supplier.

2. Material supplied to RMN was not ordered ASME.

3. RMN vendor, Fry, procured material from Timken and altered Timken's Certified Mill Test Report (CMTR).

4. Timken's CMTR did not reference ASME III, NCA 3800 program.

5. RMN tested each heat lot, not each piece of stock as required by ASME III, NCA 3867.4 e. The licensee's procurement document had specified the ASME requirement but had also specified that each heat/lot be tested.

The Duke engineering evaluation which determined the studs to be acceptable was based on several reasons which included the following:

1. The results of the Oconee visual and ultrasonic examinations were acceptable.

2. RMN had elected not to purchase the material as ASME certified but to upgrade it at RMN to meet requirements of NCA 3867.4 e.

3. RMN had heat treated the material, composed of 14 pieces of bar stock all from the same heat, and had met the requirements of ASME III except that it had tested only five pieces of the stock. Testing of five pieces exceeded the requirements of the Duke purchase order.

The Duke auditor found that alteration of the Timken CMTR was an attempt to correct a mistake on the original QA documents which should have been corrected by an official letter from Timken rather than by checking with Timken and then altering their documents as was done by Fry. No evidence of intentional falsification or fraud was found by the QA auditor and RMN acted in good faith to correctly supply the materials and documentation. The engineering decision is being documented in detail in a Duke evaluation report.

The inspectors verified that RMN is on the Duke approved vendors list, and has been audited by Duke within the prescribed time frame. The Duke Power Company QA Manual, Duke-1, as implemented by the QA Department QC procedures manual, procedure QCG-1, step 4.4.1.c, states, "Items shall be verbally released when the required documents above are not present on-site, but are located within the Duke system". It appears that step 'c' was not followed in that verbal release of the studs for use prior to having QA approved documents in the Duke system was in violation of Duke procedures. Also, the purchase order appears to be ambiguous in referencing a code which required testing of each piece of stock material while also requiring that only each heat/lot be tested. Further review is needed to determine if violations of NRC regulations occurred; therefore this item will be held at present as an unresolved item, (UNR) 270/85-10-03, Documentation concerning reactor coolant pump studs.

15. Response to Regional Office Notice (RON) No. 2201, "Station Battery Operation, Maintenance and Inspection"

The inspection by the residents covered three main areas:

Review of all procedures and vendor manuals against identified problems in the RON. The procedures reviewed are identified in enclosure to this paragraph.

Visual inspection of the battery areas for likely problems identified in the RON.

Observation of the daily, monthly, and annual tests on the power and control batteries.

Results of the procedures review indicated that tests are conducted on a more frequent basis than required. The weekly tests are done daily and the quarterly tests are done monthly. Problems identified were:

Both IEEE 450 and the battery manual OM-320-0012001 require that an equalizing charge must be given at least three days and not more than seven days before a capacity test. The capacity tests for Oconee do not require an equalizing test be performed prior to a capacity test.

The procedure for operation of individual cell chargers, IP/O/A/3000/12, does not require jumpering out of the cell or independence of the cell charger as specified in IEEE 384-1977.

A visual inspection of the batteries revealed the following:

The filler material (styrofoam) between the cells is missing or in pieces between the cells on the lower banks of batteries 1CA, 1CB, and 2CB.

An individual cell charger was in use on 4/10/85 which violated class 1E independence as specified in IEEE 384-1977. The charger was being used on cell 46 of 2CA while the cell was connected in line to the rest of the cells.

Procedure IP/O/A/3000/12, "Operation of Individual Cell Chargers", step 10.4, requires the voltage to be adjusted between 2.35 - 2.7 Vdc and current limited to 1-10 amps. The amperage reading was 11.5 amps and there was no needle on the voltmeter gage.

The inspectors could find no criteria as to when to change out a cell due to its failing surveillance test(s).

Observation of daily, monthly and annual tests detected no problems.

The inspectors were informed that Oconee has made no commitment to meet IEEE 450. A search of the FSAR and TS corroborates that there is no commitment to IEEE 450.

Until resolution to the questions raised in this paragraph have been determined, this will be listed as an unresolved item; UNR 269, 270, 287/85-10-04; Station battery operation and maintenance.

The following procedures were reviewed:

1. IP/O/A/400/11 Keowee 125 Vdc Control Battery Capability Test Using EPE Battery Analyzer

2. IP/O/A/385/1A SSF 125 Vdc Batteries DCSF and DCSFS Daily Surveillance

3. IP/O/A/0385/01B SSF 125 Vdc Battery Capability Test

4. IP/O/A/385/1C Instructions for Conducting Equalizing Charge for SSF Batteries

5. IP/O/A/385/1D SSF 125 Vdc Batteries DCSF and DCSFS Monthly Surveillance

6. IP/O/A/385/1E SSF Preventative Maintenance Procedure for Power Conversion 35-130-1000 CE Float Charge

7. IP/O/A/3000/1 125 Vdc I&C Battery Daily Surveillance

8. IP/O/B/3000/1A Power Battery Daily Test

9. IP/O/A/3000/C Removal, Installation and Jumpering of Cells

10. IP/O/B/3000/1B 525 kv Switchyard Battery Daily Test

11. IP/O/A/3000/1D 230 kv Switchyard Battery Daily Test

12. IP/O/A/3000/11 125 Vdc I&C Battery Monthly Surveillance

13. IP/O/B/3000/11A 125 Vdc Power Battery Monthly Test

14. IP/O/B/3000/11D 230 kv Switchyard Battery Monthly Test

15. IP/O/B/3000/11B 525 kv Switchyard Battery Monthly Surveillance

16. IP/O/A/3000/B Cleaning and Inspection of Battery Terminals and Intercell Connections

17. IP/O/A/3000/1C Station Battery Capacity Test

18. IP/O/A/3000/2A Operation of EPE Constant Current Battery Charger

19. IP/O/A/3000/3 125 Vdc I&C Battery Capability Test

20. IP/O/A/3000/4 Instructions for Conducting Equalizing Charge for Station Power Battery and 525 kv Batteries

21. IP/O/A/3000/4B Instruction for Conducting Equalizing Charge for 230 kv System Batteries