148 FERC ¶ 61,108
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

Imperial Irrigation District Docket No. IN14-7-000

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued August 7, 2014)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Office of Enforcement (Enforcement), the North American Electric Reliability Corporation (NERC), and Imperial Irrigation District (IID). This order is in the public interest because it resolves on fair and reasonable terms an investigation of IID, conducted by Enforcement in coordination with NERC and the Commission's Office of Electric Reliability (OER), into possible violations of Reliability Standards associated with IID's operation of a portion of the Bulk Power System (BPS) and a blackout that occurred on September 8, 2011. IID agrees to pay a civil penalty of $12,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $9,000,000 will be invested in reliability enhancement measures that go above and beyond mitigation of the violations and the requirements of the Reliability Standards. IID also agrees to commit to mitigation and compliance measures necessary to mitigate the violations described in this Agreement, and to make semi-annual compliance reports to Enforcement and NERC for at least one year.

I. Background

2. IID is a not-for-profit, publicly-owned, vertically-integrated utility and political subdivision of the State of California that primarily serves the Imperial and Coachella Valley areas of California. Pertinent to this investigation, IID is registered as a Balancing Authority (BA), Transmission Owner (TO), Transmission Operator (TOP), Transmission Planner (TP) and Planning Authority (PA), responsible for resource and transmission planning, load balancing, and frequency support, among other functions, for its footprint. IID has hydroelectric, oil-, coal- and gas-fired generation facilities, with a total net capability of 514 MW, and purchases power to meet its peak load, which can exceed 990 MW. IID's transmission system consists of approximately 1,400 miles of 500, 230,

161 and 92 kV lines, as well as 26 transmission substations. IID is subject to the Commission's regulation under section 215 of the Federal Power Act (FPA).[1]

3. On March 16, 2007, in Order No. 693, [2] the Commission approved the initial Reliability Standards, which became mandatory and enforceable within the contiguous United States on June 18, 2007.

4. The investigation of IID arose out of a system disturbance that occurred on the afternoon of September 8, 2011 in the Pacific Southwest, which resulted in cascading outages and left approximately 2.7 million customers (equivalent to five million or more individuals) without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service Company's Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through IID's service territory, into Southern California.

5. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

6. These redistributed flows traveled through IID's and Western Area Power Administration-Desert Southwest's (Western-DSW's) facilities, onto Western Electricity Coordinating Council (WECC)[3] Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from Southern California Edison Company's (SCE's) territory in Los Angeles to San Diego. The increased power flows

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[1] 16 U.S.C. § 824o (2012).

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[3] At the time of the event, WECC was registered with NERC as the Reliability Coordinator (RC) for all of the entities affected by the event, as well as serving as the Regional Entity (RE) under a delegation agreement with NERC. Since the event, the Regional Entity and Reliability Coordinator functions have been bifurcated, with WECC remaining the Regional Entity, and Peak Reliability becoming the independent Reliability Coordinator. *See Order on Compliance*, 146 FERC ¶ 61,092 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation).

parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions, voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading on Path 44 initiated an intertie separation scheme owned and operated by SCE at the San Onofre Nuclear Generating Station (SONGS) in Southern California. Initiation of the intertie separation scheme at SONGS separated San Diego Gas & Electric (SDG&E) from Path 44, contributed to tripping the SONGS nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comisión Federal de Electricidad's (CFE's) Baja California Control Area in Mexico.

7. IID's next-day plan for September 8, 2011, which was not based on updated power flow studies, indicated that if both of IID's Coachella Valley transformers tripped, its Ramon 230/92 kV transformer would trip and the Imperial Valley to El Centro "S" Line tie with SDG&E would overload to 109% of its normal rating.

8. At the time of the event, the S line had a remedial action scheme (RAS) intended to protect El Centro's 161/92 kV transformer, which would trip generation interconnected by SDG&E and ultimately trip IID's S line, if flows from SDG&E into IID exceeded preset thresholds. IID's next-day plan predicted that if the Coachella Valley and Ramon transformers tripped, Imperial Valley generation would also trip, because the S Line RAS tripped generation when it overloaded to 108% or more of its normal rating.

9. On September 8, 2011, approximately 44 minutes before the loss of H-NG, IID's real-time contingency analysis (RTCA) showed that the loss of the first Coachella Valley transformer would result in an overload of the second Coachella Valley transformer above its trip point. IID's operator checked the RTCA at the beginning of his shift, but he was not monitoring the RTCA results, nor did IID's RTCA system have an audible alarm, and thus the IID operator did not take any corrective action in response to this RTCA result.

10. Once H-NG tripped, IID and Western-DSW were forced to carry approximately 23 percent of the redistributed power flow that had initially been carried by H-NG. Carrying this extra power flow led to overloads on IID's system. IID's Coachella Valley 230/92 kV transformer overload protection relays immediately detected overloads to more than 191 MVA, well above the overcurrent relay setting. Less than a minute after H-NG tripped, Coachella Valley bank No. 2 tripped on the 230 kV side, and Coachella Valley bank No. 1 tripped milliseconds later. IID's Ramon 230/92 kV transformer bank tripped on the 92kV side less than five minutes after the loss of H-NG, which resulted in automatic undervoltage load shedding in IID's northern 92 kV system and the loss of multiple generators and transmission lines.

11. After the loss of its El Centro to Pilot Knob line, IID's southern system could only access generation from SDG&E through the S Line. The S line RAS initiated the tripping of two generators at Central La Rosita in Mexico (where a third unit had already been lost shortly after H-NG tripped) and, four seconds later, tripped the S line itself. Once the S line tripped, IID was an island, without sufficient generation, and IID lost its remaining load. In all, IID lost 929 MW of firm load during the event.

II. <u>Investigation</u>

12. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the BPS were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[4] The Report discusses a detailed sequence of events, simulations, and findings related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of bulk electric system (BES) equipment, System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs), and protections systems.

13. Following publication of the Report, Enforcement, OER and NERC staff reviewed the data gathered during the inquiry for compliance implications. At the direction of the Commission, Enforcement initiated non-public investigations of several entities, including IID, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2013), which were conducted jointly with NERC.

14. Enforcement and NERC determined that IID violated the Transmission Operations (TOP-) and Transmission Planning (TPL-) groups of Reliability Standards. The TOP standards cover the responsibilities and decision-making authority for reliable operations and aim to ensure that the transmission system is operated within operating limits. The TPL standards mandate periodic assessments to ensure that the system can meet performance requirements upon the loss of one or more BES elements, allowing

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[4] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* <u>http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf</u>.

sufficient lead time for upgrades to meet future system needs. Enforcement and NERC found these violations to be serious deficiencies undermining reliable operation of the BPS.

15. Enforcement and NERC determined that IID violated ten Requirements of four Reliability Standards— TOP-002-2a Requirements R4, R5, R6, R10, and R11, TOP-004-2 R1, R2 and R4, TPL-002-0 R1and TPL-003-0a R1.

16. Enforcement and NERC determined that IID failed to have valid next-day and current-day plans and failed to coordinate its operations planning with neighbors, in violation of TOP-002-2a R4, R5, R6, R10, and R11. Of these, IID self-reported potential violations of TOP-002-2a R5 and R11. Enforcement and NERC also determined that IID established invalid SOLs and thus did not operate within valid SOLs, which caused it to operate in an unknown state and experience cascading outages as the result of a single contingency, in violation of TOP-004-2 R1, R2 and R4.

17. Enforcement and NERC determined that IID's near- and long-term planning studies were deficient in that they failed to consider the loss of H-NG, which produces more severe system results than other facilities IID did consider, and failed to consider the effects of control devices and protection systems, in violation of TPL-002-0 R1and TPL-003-0a R1.

III. <u>Stipulation and Consent Agreement</u>

18. Enforcement, NERC and IID resolved this matter by means of the attached Agreement. IID stipulates to the facts recited in the Agreement and agrees to pay a civil penalty of $12,000,000, of which $3,000,000 will be paid to the United States Treasury and NERC, divided in equal amounts, and $9,000,000 will be invested in reliability enhancement measures that go above and beyond the requirements of the Reliability Standards, as described in the Agreement. IID neither admits nor denies that its actions constituted violations of the Reliability Standards.

19. IID also agrees to additional mitigation measures, and to submit to compliance monitoring, as specified in the Agreement.

20. In consideration of the appropriate sanction, Enforcement considered that IID has made significant efforts to date to address reliability concerns identified in the inquiry and investigation and also by IID on its own initiative. IID also fully and comprehensively cooperated with Enforcement and NERC during the investigation.

IV. Determination of the Appropriate Sanctions

21. The civil penalty amount is consistent with the Penalty Guidelines.[5] Enforcement considered that the event caused a loss of 10,000 or more MWh of firm load, and IID was allocated a share of the base penalty. IID also has a prior history of violations of the Reliability Standards, including some of the same standards found to be violated in this investigation.[6] The civil penalty amount reflects credit for IID's full cooperation during the course of the investigation as well as credits for avoiding a trial-type hearing and having an effective compliance program.

22. The Commission concludes that the penalties and other sanctions set forth in the Agreement are a fair and equitable resolution of this matter and are in the public interest. The Commission also concludes that the reliability enhancement measures set forth in the Agreement will enhance the reliability of the BPS and are therefore also fair and in the public interest.

The Commission orders:

The attached Stipulation and Consent Agreement is hereby approved without modification.

By the Commission. Commissioner Bay is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

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[5] *Enforcement of Statutes, Orders, Rules and Regulations*, 132 FERC ¶ 61,216 (2010).

[6] *See*, *e.g.*, Docket Nos. NP11-128 (included violations of TOP-002-2 R4 and R11 as well as TPL-003-0 R1), NP10-160 (included TPL-003-0 R1).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Imperial Irrigation District) Docket No. IN14-7-000

STIPULATION AND CONSENT AGREEMENT

I. INTRODUCTION

1. Staff of the Office of Enforcement (Enforcement) of the Federal Energy Regulatory Commission (Commission), the North American Electric Reliability Corporation (NERC), and Imperial Irrigation District (IID) enter into this Stipulation and Consent Agreement (Agreement) to resolve a non-public investigation conducted by Enforcement and NERC pursuant to Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2013). The investigation examined possible violations of NERC Reliability Standards by IID related to a system event in the Pacific Southwest on September 8, 2011 (September 8 event or event). IID neither admits nor denies that it violated the Reliability Standards described in this Agreement, but agrees to pay a civil penalty of $12,000,000, of which $3,000,000 shall be paid to the United States Treasury and NERC, divided in equal amounts, and $9,000,000 will be invested, subject to Enforcement and NERC approval, by IID in reliability enhancement measures identified below that go above and beyond the Agreement's mitigation commitments or what the Reliability Standards require (Reliability Enhancements). IID also commits to mitigation and compliance measures going forward, subject to compliance monitoring, as detailed in the Agreement.

II. STIPULATED FACTS

2. Enforcement, NERC, and IID hereby stipulate and agree to the following facts.

1. A. IID

3. IID is a not-for-profit, publicly-owned, vertically-integrated utility and political subdivision of the State of California that primarily serves the Imperial and Coachella Valley areas of California. Pertinent to this investigation, IID is registered as a Balancing Authority (BA), Transmission Owner (TO) and Transmission Operator (TOP), Transmission Planner (TP) and Planning Authority (PA), responsible for resource and transmission planning, load balancing, and frequency support, among other functions, for its footprint. IID has hydroelectric,

oil-, coal- and gas-fired generation facilities, with a total net capability of 514 MW, and purchases power to meet its peak load, which can exceed 990 MW. IID's transmission system consists of approximately 1,400 miles of 500, 230, 161 and 92 kV lines, as well as 26 transmission substations.

B. Event Description

4. During an 11-minute period on the afternoon of September 8, 2011, a system disturbance occurred in the Pacific Southwest, resulting in cascading outages and leaving approximately 2.7 million customers without power, some for multiple hours extending into the next day. The total load loss for the event was in excess of 30,000 MWh. The event started with a three-phase fault which led to the loss of Arizona Public Service's (APS's) Hassayampa-N. Gila 500 kV transmission line (H-NG). This transmission line is a segment of the Southwest Power Link (SWPL), a major transmission corridor transporting power in an east-west direction, from generators in Arizona, through IID's service territory, into Southern California.

5. With the SWPL's major east-west corridor broken by the loss of H-NG, power flows instantaneously redistributed throughout the electric system in the Pacific Southwest and Southern California, increasing flows through lower voltage systems parallel to the SWPL as power continued to flow on a hot day during hours of peak demand.

6. These redistributed flows traveled through IID's and Western Area Power Administration-Desert Southwest's (Western-DSW's) territories, onto Western Electricity Coordinating Council (WECC)[7] Path 44, an aggregation of five 230 kV transmission lines that deliver power in a north-south direction from Southern California Edison Company's (SCE's) territory in Los Angeles to San Diego. The increased power flows parallel to the SWPL, together with lower than peak generation levels in California and Mexico, led to significant voltage deviations and transmission equipment overloads. The flow redistributions,

[7] At the time of the event, WECC was registered with NERC as the Reliability Coordinator (RC) for all of the entities affected by the event, as well as serving as the Regional Entity (RE) under a delegation agreement with NERC. Since the event, the Regional Entity and Reliability Coordinator functions have been bifurcated, with WECC remaining the Regional Entity, and Peak Reliability becoming the independent Reliability Coordinator. *See Order on Compliance*, 146 FERC ¶ 61,092 (2014) (accepting compliance filings submitted by NERC and WECC and eliminating all final obstacles to bifurcation). The Agreement will refer to WECC when relevant to the event, and will otherwise refer to the relevant function (RE or RC) rather than using the entity names WECC or Peak Reliability.

voltage deviations, and resulting overloads had a cascading effect, as transmission and generation equipment tripped offline in a relatively short time period. Just seconds before the blackout, Path 44 carried all flows into San Diego as well as parts of Arizona and Mexico. This excessive loading on Path 44 initiated an intertie separation scheme owned and operated by SCE at the San Onofre Nuclear Generating Station (SONGS) in Southern California. The California Independent System Operator (CAISO) is responsible for many of the TOP functions for SCE under a Coordinated Functional Registration.[8] Initiation of the intertie separation scheme at SONGS separated San Diego Gas & Electric (SDG&E) from Path 44, contributed to tripping the SONGS nuclear units offline, and eventually resulted in the complete blackout of San Diego and Comision Federal de Electricidad's (CFE's) Baja California Control Area.

7. IID's role in the September 8, 2011 event centered on its location between two parallel high voltage paths—the SWPL and Path 44—into Southern California. IID and Western-DSW (also located between the two parallel paths) were forced to carry approximately 23 percent of the redistributed power flow that had initially been carried by H-NG. Carrying this extra power flow led to overloads on IID's system. Following the loss of H-NG, IID's Coachella Valley 230/92 kV transformer overload protection relays immediately detected overloads to more than 191 MVA, well above the overcurrent relay setting. Less than a minute after H-NG tripped, Coachella Valley bank No. 2 tripped on the 230 kV side, and Coachella Valley bank No. 1 tripped milliseconds later. IID's Ramon 230/92 kV transformer bank tripped on the 92kV side less than five minutes after the loss of H-NG, which resulted in automatic undervoltage load shedding in IID's northern 92 kV system and the loss of multiple generators and transmission lines. The Coachella Valley and Ramon transformers were not classified by WECC as Bulk Electric System (BES) elements before September 8, 2011, but WECC RC and CAISO did have the ability to receive real-time data on the Coachella Valley and Ramon transformers. IID's system connects with SDG&E's system at the Imperial Valley substation. After the loss of its El Centro to Pilot Knob line, IID's southern system could only access generation from SDG&E through the Imperial Valley to El Centro "S" line. At the time of the event, the S line had a remedial action scheme (RAS), operated by SDG&E, intended to protect El Centro's 161/92 kV transformer, which would trip generation interconnected by SDG&E and ultimately trip IID's S line, if flows from SDG&E into IID exceeded preset thresholds. The S line RAS initiated the tripping of two generators at Central La

[8] JRO00009 was originally entered into on September 11, 2008 and most recently updated on May 24, 2012. JRO00009 delineates compliance responsibility for the Standards and Requirements associated with the TOP function between CAISO and SCE.

Rosita in Mexico (where a third unit had already been lost shortly after H-NG tripped) and, four seconds later, tripped the S line itself. Once the S line tripped, IID was an island, without sufficient generation, and IID lost its remaining load. In all, IID lost 929 MW of firm load during the event. IID's next-day plan for September 8, 2011, which was not based on updated power flow studies, indicated that if both Coachella Valley transformers tripped, the Ramon 230/92 kV transformer would trip and the S Line tie with SDG&E would overload to 109% of its normal rating. IID's next-day plan also indicated that such an overload would result in tripping generation, because the S Line RAS trips generation supplied to Imperial Valley when the S Line loads to 108% of its normal rating. On September 8, 2011, approximately 44 minutes before the loss of H-NG, IID's real-time contingency analysis (RTCA) showed that the loss of the first Coachella Valley transformer would result in an overload of the second Coachella Valley transformer above its trip point. IID's operator checked the RTCA at the beginning of his shift, but he was not monitoring the RTCA results, nor did IID's RTCA system have an audible alarm, and thus the IID operator did not take any corrective action in response to this RTCA result.

III. INQUIRY AND INVESTIGATION

8. On September 9, 2011, the Commission and NERC announced a joint inquiry to determine how the blackout occurred and to make recommendations to avoid similar situations in the future. The inquiry team, comprised of Commission and NERC staff, used on-site visits and interviews, detailed computer modeling, event simulations, and system analyses to make its findings and recommendations for preventing similar events in the future. The inquiry determined that entities responsible for planning and operating the Bulk-Power System (BPS) were not prepared to ensure reliable operation or prevent cascading outages in the event of a single contingency. On May 1, 2012, the inquiry team published a report entitled *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (the Report), which is hereby incorporated by reference.[9] The Report discusses a detailed sequence of events, simulations, and findings related to the causes of the cascading outages. The Report also makes twenty-seven recommendations related to next-day planning, seasonal planning, near- and long-term planning, situational awareness, consideration of Bulk Electric System (BES) equipment, system operating limits (SOLs) and Interconnection Reliability Operating Limits (IROLs), and protection systems. For purposes of the Agreement, IID neither admits nor denies the sequence of events, simulations, and findings related to the causes of the outages contained in the Report.

[9] *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations* (April 2012), *available at* http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

9. Following publication of the Report, Enforcement and NERC reviewed the data gathered during the inquiry for compliance implications. As a result of that review, Enforcement and NERC initiated non-public investigations of several entities, including IID, under Part 1b of the Commission's regulations, 18 C.F.R. Part 1b (2013). Enforcement and NERC determined that IID violated ten Requirements of four Reliability Standards and found that these violations undermined the reliability of the BPS and contributed to the September 8 event. IID filed a self-report identifying potential violations of two Requirements of the Reliability Standards in connection with the event: TOP-002-2a R5 and R11. Enforcement and NERC recognized, however, that after the event and during the inquiry and investigation, IID voluntarily began making improvements in its planning and operations procedures, and implementing recommendations from the Report, that addressed many of the findings arising from the Report. In addition, IID fully and comprehensively cooperated with Enforcement and NERC during the investigation.

10. As part of the investigation, Enforcement and NERC reviewed IID's compliance program and found that IID satisfies the criteria for an effective compliance program under the Commission's Penalty Guidelines.[10] Enforcement and NERC considered the elements of IID's compliance program set forth in this paragraph: IID's compliance program is supported by a dedicated staff, the Reliability Compliance Office, devoted to evaluating and responding to compliance issues. The compliance staff is headed by an independent Reliability Compliance Officer who has independent access to the General Manager and Board of Directors. Senior management and the Board support compliance through their participation in the Reliability Compliance Steering Committee, which meets at least quarterly and is chaired by the Reliability Compliance Officer. Roles and responsibilities for meeting compliance are clearly defined and documented. IID has several mechanisms for monitoring compliance, including annual internal assessments, as well as external assessments and mock audits conducted annually. IID also has effective tools for responding to and reporting potential compliance violations, including an anonymous reporting hotline staffed by a third party service.

IV. VIOLATIONS

11. Enforcement and NERC determined that IID violated ten Requirements of four Reliability Standards— TOP-002-2a R4, R5, R6, R10, and R11, TOP-004-

[10] *Enforcement of Statutes, Orders, Rules and Regulations,* 132 FERC ¶ 61,216, § 1B2.1 (2010).

2 R1, R2 and R4, TPL-002-0 R1and TPL-003-0a R1.

A. Violations Related to Transmission Operations

12. Enforcement and NERC determined that IID failed to have valid next-day and current-day plans and failed to coordinate its operations planning with neighbors, in violation of TOP-002-2a R4, R5, R6, R10, and R11. Of these, IID self-reported potential violations of TOP-002-2a R5 and R11. Enforcement and NERC also determined that IID established invalid SOLs and thus did not operate within valid SOLs, which caused it to operate in an unknown state and experience cascading outages as the result of a single contingency, in violation of TOP-004-2 R1, R2 and R4.

B. Violations Related to Transmission Planning

13. Enforcement and NERC determined that IID's near- and long-term planning studies were deficient in that they failed to consider the loss of H-NG, which produces more severe system results than other facilities IID did consider, and failed to consider the effects of control devices and protection systems, in violation of TPL-002-0 R1and TPL-003-0a R1.

V. REMEDIES AND SANCTIONS

14. IID stipulates to the facts as described in Section II of this Agreement, but neither admits nor denies Enforcement and NERC's findings that its conduct violated the Reliability Standards specified in Section IV. For purposes of settling any and all civil and administrative disputes within the jurisdiction of the Commission arising from the reliability issues related to the September 8 event and Enforcement's and NERC's investigation, IID agrees to the remedies set forth in the following paragraphs.

A. Civil Penalty

15. IID agrees to a total civil penalty in the amount of $12,000,000, of which $3,000,000 shall be paid, in equal amounts, to the United States Treasury and NERC, within 10 days of the Effective Date. Enforcement and NERC agree to give IID a partial civil penalty offset for the remaining $9,000,000, in exchange for IID completing Reliability Enhancements as set forth in Section V.B. The value of the Reliability Enhancements is expected to substantially exceed the amount of the offset.

B. Reliability Enhancements

16. In exchange for the $9,000,000 offset, IID shall construct one or more utility scale battery energy storage system(s), which individually or in the aggregate shall have 33 MVA or better capacity at 99.5% availability, and shall be located within IID's TOP area so as to enhance the reliability of the BES. The location(s) of the battery energy storage system(s) shall be approved by Enforcement and NERC staff, such approval not to be unreasonably withheld. By December 31, 2016, IID shall provide Enforcement and NERC staff with satisfactory evidence, as determined by Enforcement and NERC staff, that it has spent a minimum of $9,000,000 on the battery energy storage system(s) and of the completion of the battery energy storage system(s). If IID has not completed the battery energy storage system(s) and spent a minimum of $9,000,000 on the system(s) by December 31, 2016, IID shall pay the remainder of the $9,000,000 in equal shares to the U.S. Treasury and NERC.

C. Completed and Required Mitigation

17. IID commits to the following actions in Section II.C. designed to mitigate the Reliability Standard violations and to improve overall reliability of the BES. As indicated below, IID affirms that it has already completed most of the mitigation measures and shall complete all remaining mitigation measures no later than one year after the Effective Date of the Agreement, unless otherwise stated in Section II.C. Where IID has already implemented mitigation measures

prior to entering into the Agreement, IID shall continue operating under the practices and procedures implemented as part of the mitigation, including but not limited to participation in working groups, until such time as the RE or RC discontinues the working group or IID implements improved practices and procedures in accordance with the Reliability Standards in existence at that time. Until IID has completed all mitigation and Reliability Enhancements, any practices and procedures that purport to improve on the practices or procedures set forth in Section II.C. shall be approved by Enforcement and NERC staff, such approval not to be unreasonably withheld. IID will report on the status of all mitigation measures described in this Section and submit evidence of progress and/or completion in its compliance monitoring reports to be submitted to Enforcement and NERC pursuant to Section V.E of this Agreement.

i. Mitigation Related to Seasonal, Next-Day and Current-Day Planning

18. IID revised its Normal Operations Planning Procedure to implement documented controls and processes for current-day and next-day planning and coordination with the RC and other BAs/TOPs. Under the revised Normal Operations Planning Procedure:

a) IID shall prepare a next-day plan for each operating day (Daily Operations Guide).

b) When preparing its Daily Operations Guide/next-day plan, IID shall perform new power flow studies for each operating day when power system operating conditions have materially changed. A supervisor shall verify that a new power flow study has been performed for each day when power system operating conditions have materially changed. IID shall archive the power flow studies for a minimum of one year in a defined location.

c) IID shall review data on power system operating conditions to determine: (i) if power system operating conditions remain similar to the conditions that existed when the last power flow studies were performed, and therefore, a new power flow study is not required; or (ii) if power system operating conditions have materially changed since the last power flow studies were performed, and therefore, a new power flow study is required.

d) For purposes of determining whether a new next-day or current-day power flow study is required, IID shall consider power system operating conditions to have materially changed if, at a minimum, one of the following is true: (i) IID has added or lost 100 MW or more of local generation used to serve IID load, (ii) IID has lost an internal transmission element of 92kV or greater, (iii) any facility external to IID's system identified as a contingency in IID's Transmission Planning, next- or current-day studies, or any external facility identified by studies known to IID as impacting IID's system operations, has been lost, or (iv) any other change in circumstances has occurred, which in the professional judgment of IID's system operations engineer, system operations shift supervisor, or system operator, warrants a new power flow study.

e) IID shall participate in daily calls convened by the RC each operating day.

f) IID shall coordinate with other BAs/TOPs by submitting its next-day plans into the RC's web portal; by sharing its next-day plans directly with other BAs/TOPs upon request, if such BAs/TOPs have executed an appropriate Non-Disclosure Agreement; and by reviewing next-day plans submitted by other BAs and TOPs to the RC portal and analyzing relevant information from those plans in its Daily Operations Meeting (or as part of its data review, on non-business days);

g) IID shall hold a daily operations meeting every business day (Daily Operations Meeting). The Daily Operations Meeting shall include IID's systems operations engineer(s) for transmission and generation dispatch, transmission outage coordinator, transmission reliability operator, and generation balancing and interchange operator (or their equivalents/designees). The attendees of the Daily Operations Meeting shall review IID's Daily Operations Guide and discuss the other BAs'/TOPs' next-day plans and current power system operating conditions, including any changes identified to SOLs or IROLs, as well as identify any foreseeable significant system events and necessary operational adjustments by IID.

h) On non-business days, IID shall review data on power system operating conditions to make the determinations required by paragraphs (d) and (g), but need not hold a Daily Operations Meeting.

i) IID shall have the system operations engineer communicate to the system operators updates to IID's next-day plan based upon results of the Daily Operations Meeting (or data review, on non-business days) and any revised study.

j) IID shall conduct supplemental meeting(s), if necessary, in addition to the Daily Operations Meeting, based on new information, system changes and possible emergency situations, and shall communicate the outcome of any such meeting to system operators and other appropriate personnel as necessary to ensure corrective action.

19. IID provided training on the revised Normal Operations Planning Procedure described in the previous paragraph.

20. IID replaced the systems operation engineer who did not consistently perform next-day power flow studies to support the Daily Operations Guides.

21. IID joined the Southwest Regional Next-Day Study Coordination Group to establish clear communication channels and promote open dialogue between next-day study engineers, planners and operators of neighboring BAs/TOPs that are members of the Group.

22. IID expanded its seasonal planning studies to include shoulder months as well as revised its Normal Operations Planning Procedure to require that IID's seasonal planning studies be shared through the RC web portal.

23. IID simulated outages of each element in the WECC's 2012 heavy summer base case, including all sub-100 kV elements in the base case, to analyze impacts on IID's transmission system. This analysis showed that outages of sub-100 kV elements did not cause any SOL violations or outages on the IID system. Similarly, outages of elements with voltage levels of 100 kV and above did not cause SOL violations or outages using the same base case. Using the 2013 WECC heavy summer base case, the California Operating Study Subcommittee determined that IID's 92 kV "R" Line would exceed its normal rating upon the loss of the Palo Verde-Devers 500 kV line. Therefore, IID developed mitigation procedures and installed a relay to keep the potential overload within the emergency rating of the associated element. Due to recent changes in topology, IID no longer believes that the R Line will exceed its normal rating upon the loss of the Palo Verde to Devers Line.

24. IID verified that its long-term planning studies include control devices, such as Special Protection Systems or Remedial Action Schemes, which are reflected in the WECC base case.

25. IID reviewed its overload protection relay settings and developed and implemented a procedural control for improved coordination of its protection systems.

26. IID hired two new system operations engineers to assist with the preparation of next-day and current-day power flow studies and Daily Operations Guides, as well as to coordinate IID's next-day and current-day planning with the RC and other BAs and TOPs.

27. IID shall use the sensitivity analysis performed for long-term planning to identify external contingencies that cause the most severe impacts on IID's system and shall monitor those external contingencies in its seasonal, next-day and current-day planning.

28. In addition to coordinating with other BAs/TOPs using the RC's web portal, if a BA or TOP that has executed an appropriate non-disclosure agreement asks IID to provide information needed for the entity's next-day and current-day studies, IID shall work diligently to provide that information timely enough for it to be used in the entity's next-day and current-day studies.

ii. Mitigation Related to Transmission Operation Within SOLs and IROLs

29. IID provided training on an operating procedure pertaining to the IROL WECC RC identified for IID's operation of the Coachella Valley and Ramon transformers. When either Coachella Valley bank #4 or both Coachella Valley banks #1 and #2 are out of service, the 30-minute relay trip settings of the remaining bank(s) define the IROL. IID continues to incorporate this IROL in all of its system studies.

30. IID provided emergency operations plan training, which included SOL and IROL assessments, so that the IID system operators can identify when operating in any condition for which valid operating limits have not been determined, and take actions to restore operations to respect proven reliable power system limits within the required time.

31. To ensure that IID uses the most current SOLs/IROLs and that those SOLs/IROLs are the same for common facilities with neighboring TOPs, IID: (a) uses the most recent WECC-approved base cases; (b) participates in the Southwest Regional Next-Day Study Coordination Group; and (c) uses the RC web portal to communicate IID's SOLs/IROLs and its next-day plans to mitigate flows to operate within those SOLs/IROLs to the RC and neighboring BAs/TOPs, as well as to review the SOLs/IROLs and next-day plans to mitigate flows to operate within SOLs/IROLs submitted by neighboring BAs/TOPs.

32. Pursuant to IID's revised Normal Operations Planning Procedure, IID reviews new information on power system operating conditions, including any changes to SOLs/IROLs, and conducts supplemental studies if power system operating conditions materially change (as described in paragraph 18(d)). IID obtains and shares information on changes in system conditions (including SOLs/IROLs) through IID's daily call participation with neighboring BAs, TOPs and RC, use of the WECCnet, or direct communications with BAs and TOPs. When system conditions materially change, IID promptly updates its next-day or current-day operating plans as necessary to reflect current power system operating conditions and uploads its revised plans into the RC's web portal to make the results available to the RC and neighboring BAs/TOPs.

33. IID's revised Normal Operations Planning Procedure also now includes protocols for communicating intra-day changes in critical system conditions, including SOLs and IROLs, to the RC and other BAs/TOPs via the WECCnet or direct telephone calls. IID developed new SOL/IROL procedures that consider sub-100 kV elements and apply to both internal and external facilities. IID has a new SOL/IROL procedure that includes identification of SOLs/IROLs, the root cause of any SOL/IROL violation, how to prevent or resolve/mitigate an SOL/IROL violation, and communication with the RC and affected parties. The procedure applies to BES facilities, including major WECC transfer paths for which IID is a TOP, and any critical sub-100 kV facilities identified by IID for inclusion as BES facilities. IID conducted a study to evaluate, in particular, the SOL on IID's "S" Line, and modified the SOL to reflect increased transfer capability resulting from the installation of an additional transformer at the Coachella Valley substation.

34. IID reviewed its facility ratings for 161 kV and key 92 kV facilities against relay settings and implemented modifications to relay settings and replaced relays where appropriate to provide additional flexibility to its system operators to take actions on a pre-contingency basis. In addition, IID updated its transmission and generation facility rating methodologies to further enhance and clarify them pursuant to FAC-008-3.

35. Following the event, IID examined whether changes were needed to the Path 42 SOL and no revisions were identified as necessary at that time. However, IID shall continue to monitor and evaluate the impact of changes in transfer capacity on the Path 42 SOL and make any necessary changes to the Path 42 SOL, and any other SOLs that may be identified within the IID footprint pursuant to IID's System Operating Limit Methodology for the Planning Horizon procedure, or any successor methodology.

36. IID models its studies in accordance with its revised Normal Operations

Planning Procedure to include current SOLs/IROLs. IID's studies include the assessment to ensure reliable operations through a secure N-1 condition. IID's studies also include the assessment to determine the adequacy of real and reactive resources in order to confirm system voltages are within reliable limits during pre- and post-contingencies to ensure reliable mitigating actions.

37. IID establishes SOLs and IROLs pursuant to its System Operating Limit Methodology for the Planning Horizon procedure, which follows the methodology outlined in the WECC System Operating Limits Methodology for the Operations Horizon. Initial SOLs are determined by planning engineers and validated through seasonal, next-day and current-day studies by operations engineers. The operations engineers also identify additional SOLs/IROLs, if any, that may arise due to short-term changes in power system operating conditions such as changes in topology, facility outages, and load and generation patterns that differ from the power system operating conditions at the time the SOLs/IROLs were identified.

iii. Mitigation Related to Voltage and Reactive Control

38. IID installed a third 230/92 kV transformer at its Coachella Valley substation, thereby increasing the reactive power capacity at Coachella Valley from 300 MVA to 600 MVA.

39. IID installed an additional 161/92 kV transformer at its Ave. 58 substation. While this change was planned prior to the event, its completion following the event is significant because, along with the Coachella Valley and Ramon substations, the Ave. 58 substation is one of three main energy sources serving the Coachella Valley's summer peaking needs. Thus it helps to support voltage in the Coachella Valley.

40. IID revised its seasonal, next-day and current-day planning studies to include an assessment of real and reactive reserves and to ensure deliverability of those reserves.

41. IID provided its operators with training on the adequacy of reactive support for contingency conditions, including the dispersal of reactive resources and mitigation actions.

iv. Mitigation Related to Long-Term Planning

42. IID created a new engineering manager position to coordinate regional transmission planning activities between IID and other entities.

43. IID conducted a self-assessment to identify sub-100 kV facilities within

its system that may impact the BES, and shall use the exception process approved by the Commission to have the 27 sub-100 kV facilities identified on the confidential list that IID has provided to Enforcement and NERC declared to be BES elements, subject to the mandatory Reliability Standards.

44. IID participated in a WECC and CAISO task force to simulate the event and conducted its own analyses, such as a simulated outage of each element in the WECC base case, including all sub-100 kV elements, to analyze impacts on IID's system. Based on lessons learned from the event and its own analyses, IID reformed its past planning practices and mitigation measures. For example, IID expanded the list of external contingencies in its long-term planning assessment to a total of seventy-nine external contingencies in the following neighboring transmission systems: (i) Western-DSW's161 kV system South of the Parker; (ii) SDG&E's 500 and 230 kV system West of the Imperial Valley substation; (iii) CFE's 230 kV system from the La Rosita substation to the CFE Zona Costa; (iv) APS's Yuma area system; and (v) SCE's system West of Mirage. When performing its 2013-2022 long-term planning assessment, IID also specifically evaluated the loss of the H-NG 500 kV line under heavy flow conditions.

45. IID evaluated neighboring transmission systems involved in the September 8, 2011 event by performing power flow contingency analyses to assess thermal and voltage deviations that may affect the reliability of the IID system and other neighboring systems. Transient stability analyses also were performed on key transmission elements identified in the Report. Power flow, transient stability and post-transient reactive margin analyses were performed on each of the WECC base cases. The study assessment considered all N-1 (Category B), credible N-2 (Category C) and Extreme (Category D) Bulk transmission and Sub-transmission contingencies in the IID transmission system as well as external contingencies that are known (from past studies and operational experience) to cause the most severe impacts to the IID transmission system. This selection criterion was applied to both power flow and transient stability assessments. The transient stability assessment was performed simulating three phase faults for the selected category B, C and D contingencies. Single line to ground simulations were performed for the selected contingencies that produce a larger fault duty than the corresponding three-phase faults.

46. IID shall continue to perform a sensitivity analysis to identify external contingencies (including transfer levels) that cause the most severe impacts to IID's system.

47. IID shall continue to evaluate its long-term planning study results to identify contingencies related to internal and external elements (including sub-100 kV) and protection systems in order to identify which contingencies and protection

systems have the most severe impacts on IID's transmission system. Contingencies that have been identified to have severe impacts on IID's transmission system include outages of: (a) 500 kV Palo Verde – Devers; (b) 500 kV Hassayampa – Hoodoo Wash; (c) 500 kV Imperial Valley – Miguel; and (5) 500 kV Imperial Valley – Suncrest. IID also shall continue to work with the RE, neighboring entities and sub-regional planning groups to identify and share contingencies that have cross-border effects.

48. IID used the spring 2014 WECC Operating Study Subcommittee base case for the California-Mexico sub-region to simulate transfers above firm. IID conducted power flow, voltage deviation and stability analyses and completed its study report (including mitigation measures for any deviations) as part of the revision of its most current long-term planning assessment. IID verified that its upgrades and proposed upgrades to its transmission system addressed power system operating conditions as experienced during the September 8 event.

49. IID worked with RE staff to develop a base case which benchmarked the September 8 event, through IID's participation in the model validation by the RE committee. IID used this base case for benchmarking the IID grid topology used in its most recent long-term planning assessment.

v. Mitigation Related to Situational Awareness

50. IID installed new monitors in its system operations center and added an audible alarm function to its RTCA tool to alert its system operators to potential violations under pre-defined contingencies. System alarms with audible and visual notice include:

a. Power flow and state estimator divergence;
b. RTCA non-convergence;
c. RTCA violation detected; and
d. RTCA network failure.

Visual alarms are specific to the condition and provide detailed information to the system operator. The alarms are ranked by priority.

51. IID procured new software for load forecasting, outage coordination, and logging of system operations, and implementation of the software is expected to be completed by October 31, 2014, but shall be completed by December 31, 2014.

52. IID established a fully-functional, redundant control center to maintain situational awareness when there is a loss of monitoring equipment or applications, such as the RTCA, in the main IID system operations center.

53. IID added a fifth shift of system operators and created five new shift supervisor positions, whereby there is an immediate supervisor monitoring the actions of the system operators on each shift.

54. IID increased its Energy Management System ("EMS") staffing levels by two positions to support continuous maintenance and updating of IID's RTCA, State Estimator, training simulator, transmission outage coordination, and EMS data verification program.

55. IID assigned a controls engineer to verify the accuracy of data and maintain the integrity of Supervisory Control and Data Acquisition ("SCADA") readings.

56. IID evaluated its RTCA and determined that it is operational and runs frequently enough (every 5 minutes) to provide system operators with adequate situational awareness.

57. IID added a second trainer to IID's operational staff, with the responsibility for designing and implementing an enhanced operational training program using a training simulator procured by IID.

58. IID provided training on situational awareness and verified the competency of IID's system operators.

59. IID provided additional simulator training on outage scenarios and mitigation measures.

60. IID refined its RTCA model to more precisely represent the IID system, including sub-100 kV elements.

61. IID provided training on both IID's RTCA application and a new IID RTCA procedure, and added procedural controls to ensure that its operational staff will continue to receive timely training.

62. IID revised its RTCA procedure to require that results be continuously displayed on a screen in front of its system operators and continually monitored by them rather than checked at beginning of each shift.

63. IID obtained, in coordination with CAISO, key external data points on other neighboring systems (including SDG&E, SCE, APS, Western-DSW, Salt River Project, and CFE) and began adding those data points into IID's real-time

model used by RTCA to provide IID's system operators with greater visibility and situational awareness. IID has completed the integration of these data points into its RTCA. IID shall incorporate these external data points to evaluate and monitor contingencies related to these external facilities using RTCA, including (a) 500 kV Palo Verde – Devers line, (b) 500 kV Hassayampa – Hoodoo Wash line, (c) 500 kV Imperial Valley – Miguel line, and (d) 500 kV Imperial Valley – Suncrest line, as well as any other facilities with a significant impact on reliability, as appropriate.

64. IID enhanced its State Estimator application to ensure metering accuracies and has developed a written procedure for identifying, reporting and repairing metering inaccuracies on its system.

65. IID evaluated whether new metering equipment is needed on IID's BES facilities and other key facilities that IID determined to impact the BES, so that IID may improve the accuracy or range of its metering system. IID determined that new metering equipment is necessary, and IID agrees to install and commission all such equipment it determined to be necessary by April 1, 2015.

66. IID has improved its procedures for responding to the impairment of its monitoring capabilities. These procedures maintain plans for the loss of SCADA, RTCA, State Estimator and the loss of communication. They also cover plans for communicating with the RC and neighboring entities in case IID loses situational awareness. IID also has revised its procedures governing the exchange of information regarding the loss or change in service status of critical facilities with the RC and other impacted entities. IID has completed operator training on all of these new procedures.

vi. Mitigation Related to Modeling

67. Since the September 8 event, IID has improved its models by coordinating configuration changes with regional study groups to ensure its models have been updated to include: (1) elements that affect BPS reliability, including internal and external elements, and elements operated below 100 kV; and (2) SPSs, RASs, and other automated control devices that impact IID's system.

68. IID reviews its models at least on a seasonal basis to reflect topology and facility changes. IID will adopt a procedure requiring a minimum of a seasonal review of its operational models by December 31, 2014.

69. IID shall document procedures to ensure both timely acquisitions of data from neighboring entities and sufficient access to data from its system for

neighboring entities which have executed a nondisclosure agreement authorizing use of the data to comply with the Reliability Standards.

vii. Mitigation Related to Angular Separation

70. IID has evaluated whether any of its transmission lines are susceptible to significant phase angle differences and has determined that only one line is susceptible to significant phase angle differences under stressed conditions. IID will re-evaluate transmission facilities that experience substantial changes for susceptibility to significant phase angle differences.

71. For the line identified as susceptible to significant phase angle differences under stressed conditions, IID has developed an operating procedure to mitigate the phase angle difference and close the line. IID also shall install an alarm to alert its system operators to a significant phase angle difference and include the significant phase angle difference in its current- and next-day studies by March 1, 2015. In addition, IID shall conduct system operator training on IID's phase angle difference(s) by April 30, 2015.

viii. Mitigation Related to Protection Systems

72. IID installed new relays for the Coachella Valley and Ramon transformers with settings at 150 percent of their highest name-plate rating for 15 minutes, thereby allowing IID system operators more time to implement mitigation measures on a pre and post -contingency basis. These microprocessor relays also provide enhanced metering capabilities.

73. IID requires its operators to operate in accordance with the monitoring procedure established by WECC RC (now Peak Reliability) for the Coachella Valley transformers, and has trained them on the RC's procedure. IID has included these new settings in its seasonal, next-day and current-day planning studies.

74. IID installed new relays with enhanced metering capabilities at IID's El Centro substation and on its 92 kV "R" line to mitigate potential overloads and keep IID's facilities within their emergency ratings.

75. IID provided its operators with training on the purpose and limitation of protection systems, protection system settings, and protection system impacts, including control devices owned or operated by others that affect the IID system.

76. IID verified that its Under Frequency Load Shedding program ("UFLS") is consistent with the WECC off-nominal frequency load shedding plan and

remains effective following the operation of control devices.

77. IID has implemented a written procedure for establishing relay settings that respect emergency facility ratings, including for sub-100 kV facilities that IID determines to impact the BES. This procedure addresses how such changes will be shared with other TOPs, TPs and PCs.

78. Previously, part of the function of the S Line RAS was to trip IID's S Line when overflows occurred onto that Line that were not sufficiently mitigated by the tripping of generation interconnected by SDG&E to the Imperial Valley substation. IID represents that this function of tripping IID's S Line has since been disabled by SDG&E with IID's consent. IID does not currently own or operate any SPS or RAS. If IID submits a potential SPS or RAS to WECC or the RE for review during the compliance period, any studies provided by IID to the WECC or the RE will be made available confidentially to Enforcement and NERC upon request. IID's long-term planning studies are modeled using the WECC base case, therefore, any control devices owned and operated by other TOPs shall be reflected in IID's studies if WECC approves them for inclusion in the WECC base case. IID monitored the WECC Modeling SPS and Relays Ad Hoc Taskforce, which was responsible for ensuring WECC base cases include appropriate SPS and relay modeling, is involved in the Imperial Valley RAS committee, and is working with regional utilities to form a permanent RAS/SPS coordinating committee.

ix. Mitigation Related to Emergency Operations

79. IID analyzed the unusual conditions that occurred during the event and clarified its restoration plan, including a more refined focus on angular separation, merchant generation embedded in IID's BA area, and sub-100 kV facilities during a restoration.

80. IID revised its Emergency Operations Plan by documenting more specific procedures for coordination with other adjacent and remote BAs, coordination with the RC to identify IROLs, and the establishment of a load reduction plan. IID has analyzed its load reduction plan to ensure that it will be executed in a manner that minimizes the risk of further uncontrolled separation, loss of generation or system shutdown.

81. IID coordinated its load shedding plans with those BAs and TOPs with which it is interconnected.

82. IID has trained its operators on their authority to implement manual load shedding in response to emergencies, and the conditions which may warrant such

load shedding.

D. Other Actions Taken by IID

83. IID retained, at the direction of its senior management and Board of Directors, a consultant, and his firm, with expertise in system operations and reliability to evaluate IID's system operations, recommend and implement improvements to enhance reliability and compliance, and supervise the system operations staff until such improvements were identified and implemented. This expert served previously as the Director of Grid Operations at the CAISO.

84. IID retained two additional consulting firms, including one immediately following the event to conduct an independent assessment of the event for IID's General Manager and Board of Directors and another which continues to advise IID on compliance with Reliability Standards and has developed new, documented procedures and controls to prevent violations from occurring and enhance compliance monitoring.

85. Under the leadership of a new Energy Manager, IID realigned its organizational structure to create a new, integrated Engineering & Operations section that focuses on Safety and Quality Control, Planning & Engineering, Generation, Operations & Infrastructure, System Operations, and Compliance Administration. IID also created a new Transmission Outage Coordinator unit to improve coordination during outages.

86. To increase its focus on, and enable greater supervision of the details of its system operations, IID modified its organizational structure so that instead of a single Superintendent supervising distribution operations, as well as BA, TOP and generation operation functions at IID's system operations control center, there are now two Superintendents with distinct oversight responsibilities.

E. Compliance Monitoring

87. IID shall make semi-annual reports to Enforcement and NERC until all of the mitigation measures and Reliability Enhancements, described above, have been fully implemented and verified by Enforcement and NERC. The first semi-annual report shall cover the first six month period after the Effective Date of the Agreement and shall be submitted to Enforcement and NERC staff within thirty days later. The subsequent reports shall be due in six month increments thereafter. Each report shall detail the following: (1) actions taken as of the date of the report to satisfy the terms of the Agreement, including all mitigation items and Reliability Enhancements; (2) actions taken to improve reliability compliance, including investments in new measures and training activities during the reporting

period; and (3) any additional violations of Reliability Standards that have occurred and whether and how IID has addressed those new violations. The reports must include an affidavit executed by an officer of IID that the compliance reports are true and accurate and also include corroborative documentation or other satisfactory evidence demonstrating or otherwise supporting the content of these reports. Enforcement and NERC staff may require additional semi-annual reporting if circumstances indicate the need for further monitoring.

VI. TERMS

88. The "Effective Date" of the Agreement shall be the date on which the Commission issues an order approving the Agreement without material modification. When effective, the Agreement shall resolve all reliability matters relating to the September 8 event within the jurisdiction of the Commission, and that arose on or before the Effective Date, as to IID or any affiliated entity.

89. Commission approval of the Agreement without material modification shall release IID and forever bar the Commission and NERC from holding IID, any affiliated entity, and any successor in interest to IID liable for any and all administrative or civil claims arising out of the reliability issues related to the September 8 event or the conduct addressed and stipulated to in the Agreement that occurred on or before the Agreement's Effective Date.

90. Failure to make the civil penalty payment or comply with the mitigation, Reliability Enhancements, and monitoring agreed to herein, or any other provision of the Agreement, shall be deemed a violation of a final order of the Commission issued pursuant to the Federal Power Act (FPA), 16 U.S.C. §792, *et seq.*, and may subject IID to additional action under the enforcement provisions of the FPA.

91. If IID does not make the cash civil penalty payment described above at the time agreed by the parties, interest payable to the United States Treasury and NERC will begin to accrue pursuant to the Commission's regulations at 18 C.F.R. § 35.19(a)(2)(iii)(2013) from the date that payment is due, in addition to the penalty specified above and any other enforcement action and penalty that the Commission or NERC may take or impose.

92. The Agreement binds IID and its agents, successors, and assignees. The Agreement does not create any additional or independent obligations on IID, or any affiliated entity, its agents, officers, directors, or employees, other than the obligations identified in the Agreement.

93. The signatories to the Agreement agree that they enter into the Agreement voluntarily and that, other than the recitations set forth herein, no

tender, offer or promise of any kind by any member, employee, officer, director, agent or representative of Enforcement, NERC, or IID has been made to induce the signatories or any other party to enter into the Agreement.

94. Unless the Commission issues an order approving the Agreement in its entirety and without material modification, the Agreement shall be null and void and of no effect whatsoever, and Enforcement, NERC and IID shall not be bound by any provision or term of the Agreement, unless otherwise agreed to in writing by Enforcement, NERC and IID.

95. IID agrees that the Commission's order approving the Agreement without material modification shall be a final and unappealable order assessing a civil penalty under the Federal Power Act. IID waives findings of fact and conclusions of law, rehearing of any Commission order approving the Agreement without material modification, and judicial review by any court of any Commission order approving the Agreement without material modification.

96. The Agreement can be modified only if in writing and signed by Enforcement, NERC and IID, and any modifications will not be effective unless approved by the Commission.

97. Each of the undersigned warrants that he or she is an authorized representative of the entity designated, is authorized to bind such entity and accepts the Agreement on the entity's behalf.

98. The undersigned representative of IID affirms that he has read the Agreement, that all of the matters set forth in the Agreement are true and correct to the best of his knowledge, information and belief, and that he understands that the Agreement is entered into by Enforcement and NERC in express reliance on those representations.

99. The Agreement may be signed in counterparts.

100. The Agreement is executed in triplicate, each of which so executed shall be deemed to be an original.

Agreed to and accepted:

Norman C. Bay
Director, Office of Enforcement
Federal Energy Regulatory Commission

Date: 7·16·14

Charles A. Berardesco
Senior Vice President, General Counsel and Corporate Secretary
North American Reliability Corporation

Date: 7/15/14

Kevin Kelley
General Manager
Imperial Irrigation District

Date: 7/14/14