REPORT OF THE OUTAGE REVIEW TEAM

Appointed by the
Office of Utilities Regulation

TO INVESTIGATE THE ELECTRICITY SYSTEM TOTAL SHUTDOWN ON 2016 AUGUST 27

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EXECUTIVE SUMMARY

At about 5:45 pm on Saturday 2016 August 27, a fault on the Jamaica Public Service Company Limited's (JPS') 69 kV Transmission System between the Port Authority of Jamaica (PAJ) and Hunts Bay substations resulted in unstable voltage and frequency conditions. These unstable conditions in turn precipitated the tripping of all generating units online and consequently a total System failure in approximately 15 seconds after the initiation of the fault.

This was the second occasion in 2016 in which the electricity System experienced a major failure. The first of these two incidents occurred on 2016 April 17. The incident resulted in the partial shutdown of the electricity System during which, 485.03 MW of load was disconnected from the System causing customers island-wide to experience loss of electricity supply for extended periods.

Following the 2016 August 27 System failure, the OUR, pursuant to its powers under the Office of Utilities Regulation Act and the Electricity Act, 2015 (EA), decided to formally investigate the circumstances salient to the incident and to undertake analyses similar to those conducted for previous outages. As such, the OUR established a Review Team, comprising Power System experts and OUR personnel, to conduct the investigation.

In executing the investigation, the Review Team carried out a comprehensive review and evaluation of the information and data submitted by JPS in relation to the subject outage as well as reports and recommendations associated with previous major System outage that occurred in Jamaica.

The evaluation and analyses conducted by the Review Team provided the basis for the resulting Conclusions and Recommendations.

Conclusions

The Review Team has formed a number of conclusions regarding the specifics of the 2016 August 27 outage, but in the context of a broad terms-of-reference it has concluded that the System is subject to issues regarding:

i) System instability and protective relaying shortcomings;
ii) Proper planning and coordination of System operations;
iii) Maintenance approach;
iv) Compliance with operating procedures and processes;
v) Awareness and training of operating personnel.

The major conclusions specific to the 2016 August 27 outage are summarized as follows:

1) The System shutdown was initiated due to the failure of the System Operator's maintenance personnel to remove a "short-and-ground" that was installed on the 69 kV Transmission System in the vicinity of breaker 169/8-130 at the PAJ substation, to facilitate maintenance work at the substation. This precipitated a solid three phase-to-ground fault on the System upon the re-energizing of the Hunts Bay - PAJ 69 kV transmission to return the System to normal operation.

2) The primary protection scheme failed to trip the relevant circuit breaker and clear the fault as was expected.

3) The relevant Back-up protection scheme failed to clear the fault as was expected.

4) Primary "A" and "B" zone 2 distance protection operated as designed to clear the fault after a reported time of 433 ms.

5) The fault clearance after 433 ms resulted in unstable Power System conditions and caused the tripping of all on-line generators in the CA, which precipitated a cascading effect and eventual collapse of the System after approximately 15 seconds.

6) Several generating units were affected by the instability occasioned by the large power swings and the low busbar voltages and their inability to ride-through low voltage condition during System faults.

7) The early tripping of JPPC and WKPP units contributed the outage, by exacerbating the situation that triggered the System cascade which eventually led to the total System shutdown.

8) The non-functioning of a number of important communication systems during the System shutdown, affected the early analysis of the problem and therefore delayed restoration activities.

Recommendations

Recommendations applicable to the OUR

The recommendations to be considered for implementation by the OUR are as follows:

1) Promote and encourage the implementation of enforceable standards and requirements through the framework of the Jamaica Electricity Sector Book of Codes and other relevant regulations to govern the operation and control of the Power System as well as the maintenance of System components with focus on critical plant, equipment and apparatus.

2) Consider an approach to incorporate a separate reliability performance measure to address the effects of major System outages determined to be within JPS' control, as a component of the QoS requirements. This may involve compensation to customers affected by a major System failure such as the 2016 August 27 incident, which would provide a further incentive to the System Operator to ensure that its actions or operations do not adversely impact System reliability.

3) Establish an appropriate framework for the collection and reporting of data needed for post-blackout analyses, and for JPS and Independent Power Producers (IPPs) to preserve evidence as far as is possible, after a System shutdown incident.

4) Improve the existing monitoring framework to enable it to appropriately track the implementation of recommendations resulting from investigations in relation to major System failures or conditions impacting System reliability, issued by the regulator to the System Operator.

5) Through the medium of the existing regulatory mechanisms, ensure that JPS executes all the corrective actions indicated in the "Technical Report" submitted 2016 September 28.

Recommendations to JPS

The recommendations to be implemented by JPS are as follows:

1) Implement the recommendations emanating from the OUR's investigation of the 2016 April 17 System outage, in accordance with the developed Action Plan.

2) Ensure that adequate measures are introduced to forestall and prevent the recurrence of problems associated with the 2016 August 27 System shutdown, including the issues associated with the performance of the IPP's generation facilities

3) As a matter of priority, review the current switching procedures and safety rules and establish appropriate systems to ensure compliance.

4) Urgently review the policies and procedures governing all communication between System Control and Field Personnel to ensure greater accountability. Also, maintain a sound Records Management & Storage system to ensure that all communications between the System Control Centre and other operations personnel, can be properly recorded and protected, and can be accessible to the regulator to facilitate necessary investigations and audits.

5) Review and improve the T&D maintenance policies and procedures, including the SDJO and the LOTO PTW system to ensure greater accountability.

6) Urgently review operating guidelines to ensure that the System is returned to normal and reliable operation in a timely manner following a contingency event.

7) Review the training and certification requirements for all personnel involved with the operation, monitoring and maintenance of the T&D system with a view to closing any skills or competence gaps that may exist. This will require that the relevant operations & control personnel are engaged in on-going operational training, including appropriate certification training in switching and safety procedures.

8) Implement mechanisms or upgrade existing monitoring systems to ensure that System Control, the relevant maintenance personnel and management can be immediately alerted of defects which develop on critical equipment/apparatus.

9) Urgently investigate the SOTF protection scheme currently incorporated in the primary "A" distance protection and all other critical protections systems at all the relevant substations in the System to identify defects or maintenance issues, and take the necessary corrective actions to remedy identified weaknesses.

10) Urgently evaluate the primary distance protection at Hunts Bay substation and all other relevant substations in the System and incorporate the SOTF scheme in the primary "B" distance protection as a means of redundancy to improve System resilience and reliability.

11) Conduct an evaluation of the set-up, functionality, settings, coordination and maintenance practices of the protective relaying schemes installed in the Power System, as well as, resource adequacy and competence of System protection personnel. JPS may wish to share the TOR developed for the evaluation with the OUR for review, and on completion of the evaluation, a copy of the final report shall be submitted to the OUR.

12) Conduct a comprehensive assessment of the unacceptable LVRT performance of some interconnected generation facilities (JPS and IPPs) duration System disturbances, including low voltage protective schemes and settings; and make specific recommendations and take actions to guarantee that the generating units do not trip off-line spuriously and unnecessarily during major System disturbances. A copy of the report of this assessment should be made available to the OUR.

13) Require of JPPC, consistent with its interconnection agreement, to (a) correct the specific cause of the reported early tripping of its generating units on low voltage (b) take action to get the facility time synchronized.

14) Conduct Transmission System assessments and review existing T&D system studies to (a) evaluate any apparent need to upgrade and re-reinforce the 138 kV transmission network so that robust direct links are available to connect the major generating facilities directly to each other, to enhance System reliability and resiliency and reduce the possibility of System separation during major System disturbances, and (b) ensure that sufficient redundancy is embedded in the System to support optimal power flow and accommodate the System security contingency criteria stipulated in the Jamaican Electricity Sector Book of Codes.

15) Comprehensively review the overall UFLS Scheme protection scheme, with emphasis on feeder/load characteristics for peak, partial peak and light load conditions. Also, carry out

the appropriate maintenance activities on the overall automatic UFLS relay scheme to eliminate potential problems that could contribute to its mal-function or non-operation as was the case at the Hope substation during the System shutdown on 2016 August 27.

16) Conduct analysis or update relevant existing studies to determine the CFCT on the various transmission lines in the System. Also, ensure that the maximum fault clearing time setting for primary and back-up protection at all substation busbars deemed critical to System security does not exceed the determined CFCT for each busbar or transmission lines.

17) Review and evaluate the existing spinning reserve policy to ensure reliable System operation under normal operating conditions and contingency scenarios. A copy of the evaluation report shall be submitted to the OUR. In the interim, JPS will ensure that the spinning reserve allocated to the designated generating units is fully functional and can be efficiently deployed subject to the minimum specifications of the respective generating unit.

18) Take the necessary action to improve the quality of System modeling data to facilitate, inter alia, the proper post-event analyses of System performance for incidents such as the 2016 August 27 System shutdown.

19) Investigate and upgrade the communication systems as appropriate and ensure that the systems are properly maintained. Also, complete the implementation of plans for full redundancy of alternate communication signal and data routing in the event of failure of the default channel.

20) Ensure that all the SOE recorders installed in the System are made fully functional and kept in a serviceable state at all times.

21) Ensure the availability and reliability of all DFRs installed in the System and take appropriate measures to ensure that they are properly calibrated and maintained on an on-going basis.

22) Pursuant to Item 9 of the OUR's 2006 Directive pertaining to the 2006 July 15 System shutdown, take immediate action to ensure that all JPS generation stations, IPP generation facilities, JPS System Control Centre and other relevant sites in the System are time synchronized. A report on the approach to be undertaken by JPS shall first be

submitted to the OUR, after which periodic progress reports shall be submitted to the OUR based on an agreed schedule.

23) Ensure that full SCADA visibility of monitored and controlled System equipment/apparatus is a priority and that the availability of the SCADA system is consistent with international best practice, whether during; normal operation, a shutdown event or System restoration. In addition, JPS shall revise its maintenance programme for this system and shall lodge a copy of this programme with the OUR.

24) Develop an appropriate framework for the routine inspection and maintenance of all "Black Start" facilities/equipment on the System. Reports on the inspection and maintenance activities shall be submitted to the OUR as part of the "monthly technical report" submitted by the System Operator to the OUR.

JPS is required to provide a report to the OUR on the actions taken regarding the implementation of these recommendations.

Recommendations to IPPs

The recommendations applicable to the IPPs are as follows:

1) Ensure that all generation facilities equipped with Black Start facilities are kept in an available state with the start-up machines in good working order.

2) Cooperate with JPS or its agents or consultants in the performance of the required studies/assessments in relation to LVRT capabilities of the relevant generating units and other requirements critical to System reliability security.

3) JPPC is required to investigate and correct the specific cause of the reported early tripping of its generating units on low voltage, taking into account, the Interconnection Criteria and other relevant provisions included in the Jamaican Electricity Sector Book of Codes.

4) JPPC is to immediately take action to ensure that its generation facility is time-synchronized with the System.

5) Subject to the Interconnection Criteria in the Jamaica Electricity Sector Book of Codes, WKPP is required to investigate and address the early tripping of its generating units as

well as the apparent inability of the units to export active power under abnormal operating conditions.

6) JEP and WKPP in collaboration with JPS are required to perform load rejection tests at their respective generation facilities to determine the responsiveness of the generating units when subjected to abnormal System conditions.

ABBREVIATIONS

AC	-	Alternating Current
CA	-	Corporate Area
CB	-	Circuit Breaker
CCGT	-	Combined Cycle Gas turbine
CFCT	-	Critical Fault Clearing Time
DC	-	Direct Current
DFR	-	Digital Fault Recorder
EA	-	Electricity Act, 2015
ECS	-	Electronic Communication Services
EMS	-	Energy Management System
ESI	-	Electricity Supply Industry
EST	-	Eastern Standard Time
GPCR	-	Gross Plant Capability Report
GPS	-	Global Positioning System
GSU	-	Generator Step-Up
GT	-	Gas Turbine
HB	-	Hunts Bay
Hz	-	Hertz
HV	-	High Voltage
IPP	-	Independent Power Producer
JEP	-	Jamaica Energy Partners
JPPC	-	Jamaica Private Power Company
JPS	-	Jamaica Public Service Company Limited
kV	-	kilovolt
LOTO PTW	-	Lock Out Tag Out Permit-To-Work
LVRT	-	Low Voltage Ride Though
LWR	-	Lower White River
ms	-	millisecond
MVA	-	Mega Volt Amps
MVAr	-	Mega Volt Amps (reactive)
MW	-	Megawatt
NWA	-	National Works Agency
OH	-	Old Harbour
O/S	-	Out of Service

OUR	-	Office of Utilities Regulation
PAJ	-	Port Authority of Jamaica
PLC	-	Power Line Communication
POTT	-	Permissive Overreaching Transfer Trip
PPA	-	Power Purchase Agreement
PV	-	Photovoltaic
QoS	-	Quality of Service
RA	-	Rural Area
RE	-	Renewable Energy
RF	-	Rockfort
SCADA	-	Supervisory Control And Data Acquisition
SDJO	-	Substation Department Job Order
SOE	-	Sequence of Events
SMD	-	Substation maintenance Department
T&D	-	Transmission and Distribution
TLM	-	Transmission Line Maintenance
UFLS	-	Under-Frequency Load Shedding Scheme
UWR	-	Upper White River
VT	-	Voltage Transformer
WKPP	-	West Kingston Power Partners
WWFL	-	Wigton Windfarm Limited
2006 Directive	-	Directive (Ele 2006/05) issued to JPS pursuant to Section 4 of the OUR Act requiring remedial actions following the island-wide system shutdown of July 15, 2006 dated 2006 November 30

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1 INTRODUCTION

1.1 Background

On Saturday, 2016 August 27, the entire island experienced an electric power blackout which resulted from a major System incident on the Jamaica Public Service Company Limited's (JPS') electricity network. According to JPS' Major System Incident Technical Report on the 2016 August 27, Power System All-Island Blackout (the "Technical Report") submitted to the Office of utilities Regulation (OUR) on 2016 September 28, the power blackout was initiated at approximately 5:45 pm Eastern Standard Time (EST) and precipitated into a total System shutdown after approximately 15 seconds of the initiating event. This situation resulted in the loss of supply to all JPS customers, with the entire customer base experiencing power outages of varying durations from 5:45 pm until the System was fully restored at 11:22 pm.

Subsequent investigations by JPS established that the initiating cause of the System failure was a solid three-phase to ground fault on the 69 kV transmission system at the Port Authority of Jamaica (PAJ) substation located in the Corporate Area (CA).

The fault condition was in effect for approximately 433 milliseconds (ms) before it was cleared by primary "A" and "B" zone 2 distance protection designed to operate with delay of 400 ms. However, by this time the System was approaching a state of instability, causing generators online to experience varying degree of dynamic loading, which resulted in frequency and voltage excursions. These conditions had a cascading effect forcing the generators online to trip off- line and also the tripping of transmission lines leading to the eventual collapse of the entire JPS Power System.

JPS reported that the fault occurred during the process of the re-energization of the Hunts Bay – PAJ 69 kV transmission line to return it to service following a planned maintenance outage at the PAJ substation. According to JPS, the planned maintenance outage was to facilitate testing and maintenance works on critical 69 kV equipment at PAJ substation which included, cleaning of the 69kV/13.8kV T2 transformer bushings, contact timing tests on circuit breaker 169/8-430 and control panel replacement on the PAJ – Hunts Bay 69kV line disconnect switch 169/8-251. Based on JPS maintenance procedures, such maintenance activities required full work area electrical isolation as well as precautionary measures consistent with JPS' established safety procedures to eliminate or minimize the risks of adverse effects on the Power System components and personnel involved with the exercise.

The investigations so far revealed that the solid three-phase fault on the 69 kV transmission at the PAJ substation was due to a "short-and-ground" left in place on the 69 kV transmission system by JPS maintenance crew in the vicinity of breaker 169/8-130 at the PAJ substation.

Notably, a "short-and-ground" can be referred to as a safety measure/assembly that provides shock protection to personnel while working on de-energized electrical equipment in the event that such equipment becomes energized due to switching errors or other means.

The failure to remove the "short-and-ground" prior to the re-energization of the transmission line is seen as a departure from JPS' *Lock Out Tag Out Permit-To-Work* (LOTO PTW) system, applicable switching & safety procedures and prudent utility practice.

1.2 Legal and Regulatory Requirement

In the event of a major System failure due to the failure of any part of the JPS electricity System, howsoever caused, Section 45, subsections (12) and (13) of the Electricity Act, 2015 ("the EA"), provides as follows:

> *"(12) Upon the system being restored to normal operating levels after a major system failure, the System Operator shall carry out an investigation of the causes of the failure and produce a report thereon, which report shall also describe the measures and procedures to restore the system and the measures that should be taken to avoid a recurrence of the failure, and shall provide an assessment of the cost associated with the failure.*
>
> *(13) The System Operator shall submit the report under subsection (12) to the Office and to the Minister within thirty days of the system being restored to normal operating levels."*

As required under the EA, a complete report of the 2016 August 27 major System failure was due for submission by JPS to the OUR and the Minister by 2016 September 28, given that the System was restored to normal operation on the same day of the incident. Nevertheless, JPS submitted what it designated, a preliminary outage report dated 2016 August 29 on the Power System shutdown incident to the OUR on the same day. The said report purported to outline the initial findings of JPS' preliminary investigation of the outage.

Following the submission of the preliminary outage report, JPS requested a meeting with the OUR. The meeting was convened at the OUR's office on 2016 August 30 with discussions focusing on the outage, further details on JPS' ongoing investigation and its approach for complying with the relevant requirements of the EA.

Following on the August 30th meeting, the OUR wrote to JPS by letter dated 2016 September 2, specifying the information requirements and issues that it expected to be addressed in the report due to be submitted by 2016 September 28. Refer to APPENDIX 1 for the full details of the OUR's Information and Data Request from JPS for the 2016 August 27 Power Blackout (the "OUR's Information and Data Request").

In its response dated 2016 September 16, JPS indicated that it had completed a detailed assessment of the resource and time allocation to comply with the information request but contended that it was not possible in the limited time line specified in the EA to complete a report that would comply with all the OUR's requisitions. However, JPS indicated that a substantial portion of the data and information requested was available and could be included in the final report due for submission 2016 September 28.

Regarding certain elements of the OUR's information request, specifically identified as section (h) – Transient Stability Simulation Study Cases and to be included in appendices (d) – Load Flow Results – and (e) – Stability Graphs, JPS indicated that these data items could not be reasonably complied with within the 30-day stipulation. JPS further added that if the referenced data items were to be included as part of the report, it would result in significant delay in the submission of the report and this would contravene the relevant provisions of the EA.

JPS therefore proposed to:

- submit an Intermediate Report on 2016 September 28as mandated by the EA.
- complete the information requested and submit the results of the studies and simulation itemized in section (h) and appendices (d) and (e) in a Final Report on or before 2016 October 31.

The OUR by way of a letter dated 2016 September 21 indicated its non-objection to the submission of the complete data set requested by 2016 October 31 but also underscored that the final report on the 2016 August 27 System incident is required by 2016 September 28 in keeping with the relevant provisions of the EA.

For independent verification of the performance of the IPPs' generation facilities during the incident and the SOE as viewed from their respective facilities, the OUR requested reports on the

System shutdown incident from the major IPPs supplying dependable capacity to the System, in order to support its investigation and determinations.

Without prejudice to the relevant provisions of the EA, as part of its functions set out under Section 4 of the Office of Utilities Regulation Act, the Office is responsible for carrying out investigations in relation to the provision of a prescribed utility service to enable it to determine whether the interest of consumers are adequately protected.

1.3 Outage Review Team

On 2016 September 12, OUR established a Review Team to investigate the causes of the System outage and to make comprehensive recommendations in order to limit the possibility of future such occurrences.

The Review Team was comprised as follows:

- **Valentine Fagan** – Power System Specialist
- **Aston Stephens** – Power System Specialist
- **Andre Lindsay** – Regulatory Engineer
- **Courtney Francis** – Regulatory Engineer (Team Leader)

1.4 Approach

Given the developments regarding the data requirements as detailed in section 1.2 above, the Review Team divided its work into two phases:

- Phase 1: Investigate the System outage on the basis of JPS' Major System Incident Technical Report and supporting data submitted 2016 September 28, to determine its causes and why it was not contained.

- Phase 2: Conduct comprehensive evaluation and analyses of the outage and develop recommendations to reduce the possibility of future outages and to minimize the scope of any that may recur.

As part of a broad TOR, the Review Team also compared the causes of the subject System failure with the causation factors of previous major System outages that occurred in Jamaica.

1.5 Scope

This document constitutes the report issued by the Review Team, detailing the findings and recommendations.

1.6 Structure of Report

This investigation report comprises eleven chapters, including this Introduction, It also contains a number of Appendices.

- Chapter 2: Provides an overview of the Jamaican Electric Power System and the regulatory framework for ensuring the reliability of the System.

- Chapter 3: Discusses the operating conditions on the Power System before 2016 August 27 and on August 27 prior to the events directly related to the power blackout.

- Chapter 4: Addresses the causes of the Power System shutdown, with specific focus on the evolving of conditions which resulted in an uncontrollable cascading blackout.

- Chapter 5: Provides an evaluation of the System shutdown incident.

- Chapter 6: Describes activities undertaken by the System Operator to achieve full restoration of service

- Chapter 7: Provides technical analysis of the incident with emphasis on frequency stability and voltage stability.

- Chapter 8: Provides a comparison of the August 27 incident with previous major System outages that occurred in Jamaica over the past ten (10) years.

- Chapter 9: Details the observations, findings and comments arising from the investigation.

- Chapter 10: Conclusions

- Chapter 11: Recommendations

- APPENDICES

2 OVERVIEW OF THE JAMAICAN ELECTRIC POWER SYSTEM

2.1 Preamble

The provision of an adequate, safe and efficient electricity service is fundamental to the functioning of modern societies. This resource impacts almost all dimensions of today's society and electricity customers have come to expect that electricity will almost always be available when needed at the flick of a switch. Unplanned interruption in electricity supply can therefore have serious economic and social consequences.

Most electric utility customers have experienced local outages caused by various events, such as, a vehicle hitting a power pole, a construction crew accidentally damaging a power line/cable, a lightning strike, or the effect of a thunder storm. What is not expected, however, is the occurrence of a massive and sustained power outage on a bright and calm Saturday afternoon. Major power blackouts, such as the one that occurred on 2016 August 27, are usually rare events, but they can happen regularly if reliability safeguards are disregarded or given limited attention. In the case of the Jamaican Power System, the records reveal that these outages have occurred with some degree of frequency in recent years. It is noteworthy that as recent as 2016 April 17, the entire Island experienced a major System outage, largely similar to the subject outage.

Providing reliable electricity to customers is a technical challenge, even on the most routine days during System operation. It involves real-time assessment, control and coordination of electricity production at generators, movement of electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to a constantly varying customer demand via a distribution network. In that regard, the System Operator has a legal obligation to ensure that it is equipped with the necessary capability to respond to these demanding and critical requirements.

The electricity supplied to the System is normally produced by generation facilities which utilize various energy sources, such as, fuel oil, natural gas, hydro power, wind power, solar PV, etc. The bulk electricity produced at the power generation plants flows through transmission lines to substations which reduce the voltage levels for distribution to end-use customers.

2.2 Description of the Power Delivery System

In the EA and the Electricity Licence, 2016 (the "Licence"), the Transmission System is defined as the part of the electricity System that operates at 69,000 volts (69 kV) or higher while the Distribution System is the part that operates below 69,000 volts (V).

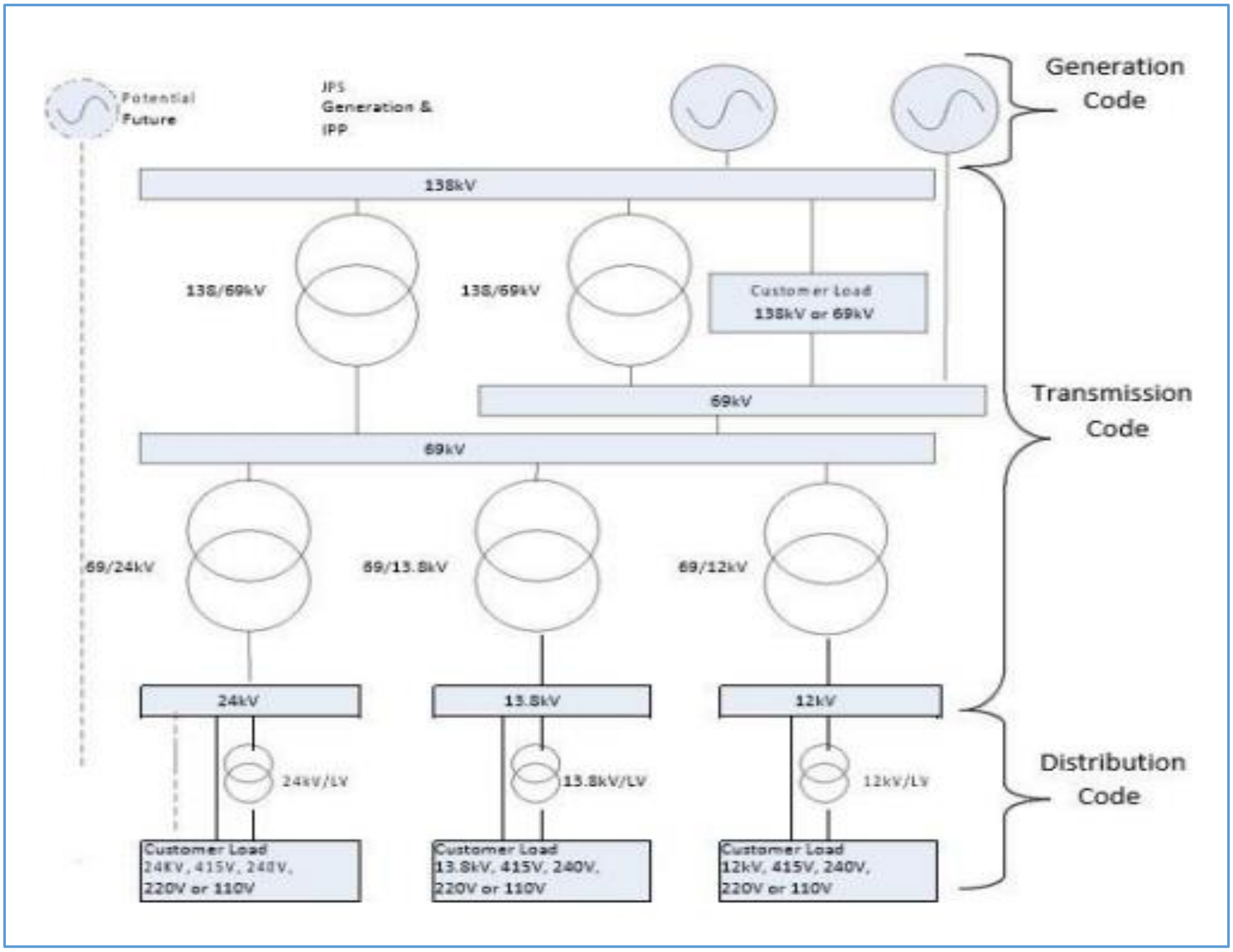
As delineated in the Jamaica Electricity Sector Book of Codes (2016 August), the boundary of the Transmission System is demarcated from the point of the HV side of the Generating Unit Step-Up (GSU) transformer and includes a network of transmission lines, switching stations, substations, and the equipment on the secondary side of transformers at transmission substations transforming to 24 kV, 13.8 kV and 12 kV down to the outgoing isolators of the Feeder - Circuit Breaker (Recloser).

The Distribution System on the other hand, extends from the point of the outgoing isolators of a Feeder – Circuit Breaker (Recloser) at transmission substations transforming to 24kV, 13.8kV and 12kV, consisting of Apparatus and meters owned and operated by the System Operator used in connection with the distribution of electricity.

A schematic representation of the System showing the boundaries between the Transmission System, Distribution System and Generation Systems is shown in Figure 2.1 below.

Based on the orientation of the System, during operation, the electricity produced by the generation plants is "stepped up" by the GSU to higher voltages and then transported over the transmission network to substations where it is "stepped down" to the primary distribution voltage levels (24 kV, 13.8 kV, 12 kV) to facilitate the distribution and supply of electricity to customers.

Figure 2.1: Schematic Diagram of the System with Boundaries between Transmission, Distribution and Generation

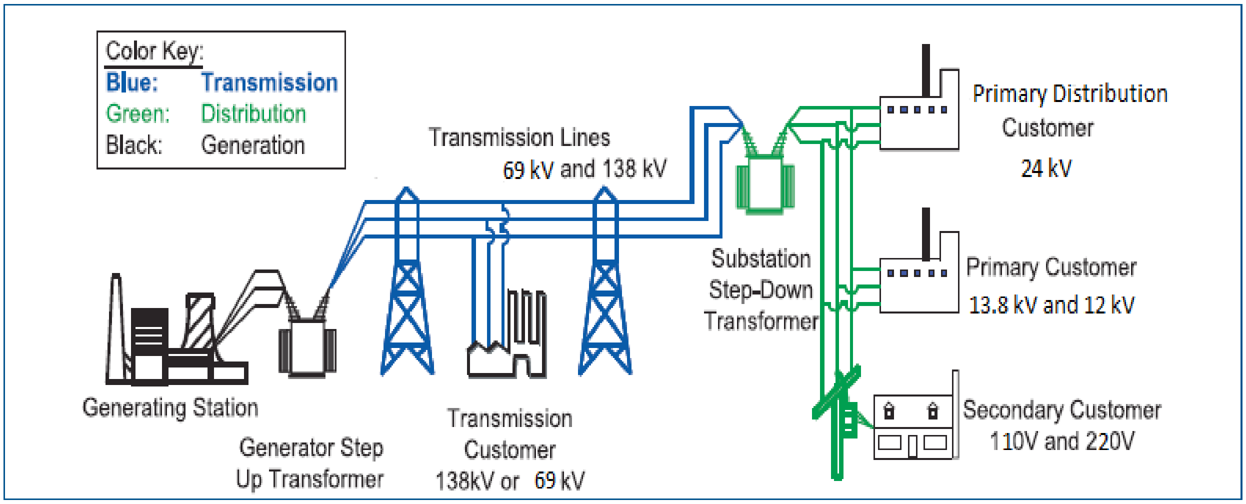


Source: Jamaica Electricity Sector Book of Codes (2016 August)

For technical and economic reasons, the System was designed and built out predominantly as an alternating current (AC) System as opposed to a direct current (DC) System, and operates at a power frequency of 50 Hz. Based on the electrical requirements of the loads connected to the System, some large commercial and industrial (C&I) customers are supplied at the 69 kV voltage level while others are supplied at the primary distribution voltage levels. However, most residential customers are supplied at secondary distribution voltages of 110 volts and 220 volts.

The orientation of the System is illustrated in Figure 2.2 below.

Figure 2.2: Orientation of the Electricity System



2.3 Market Structure

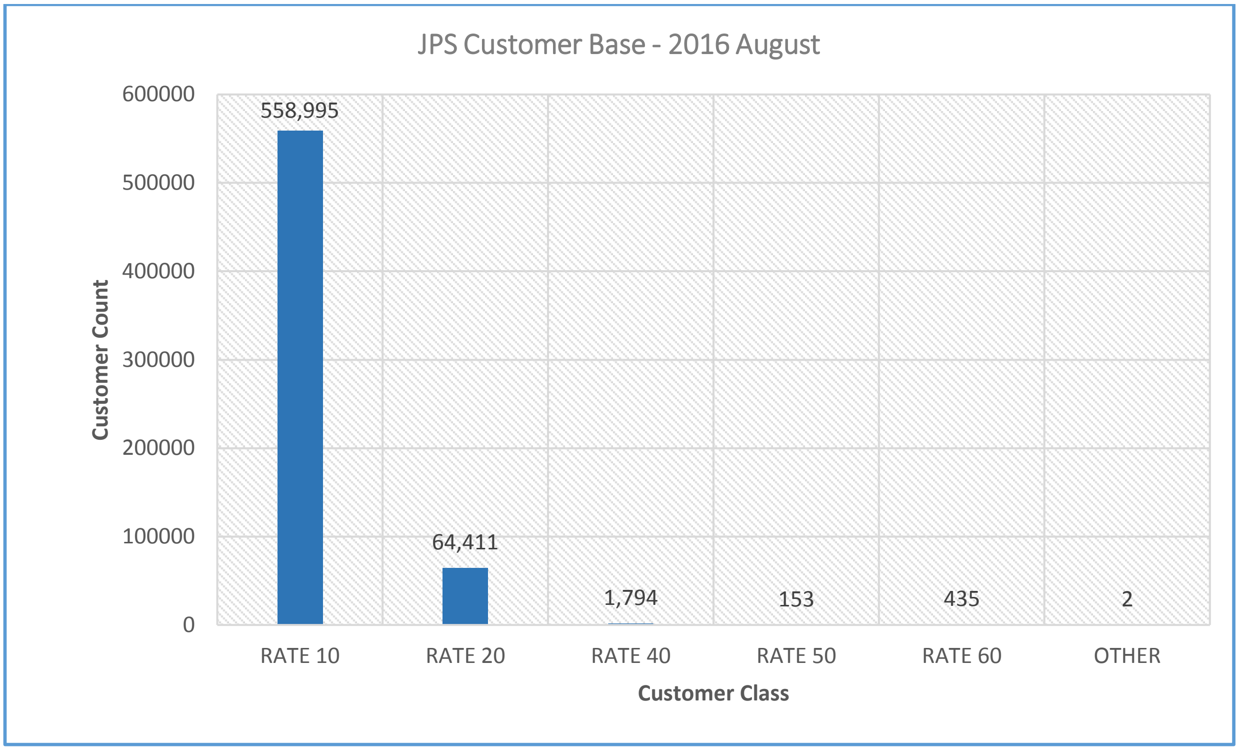
Under the EA, the electricity sector market structure is defined as a Single Buyer model which is comprised of a vertically integrated electric utility arrangement with IPP participation governed by long-term Power Purchase Agreements (PPAs). The EA designates JPS, who owns the Transmission and Distribution Systems and a significant portion of the total existing generating capacity of the Power System, as the Single Buyer/System Operator. The sector is regulated by the OUR.

Under the Licence, JPS has the responsibility to provide an adequate, safe and efficient service based on modern standards, to all parts of the Island of Jamaica at reasonable rates so as to meet the demands of the Island and to contribute to economic development.

2.4 Customer Base

In 2016 August, JPS total customer base was approximately 625,790 customers including residential (Rate 10), commercial (Rate 20) and industrial consumers (Rate 40 & Rate 50). Of this total, approximately 89% were residential customers. Figure 2.3 below shows the distribution JPS customer by class.

Figure 2.3: Distribution of JPS Customers by Class



Source Information: JPS 2016 Final Performance Data

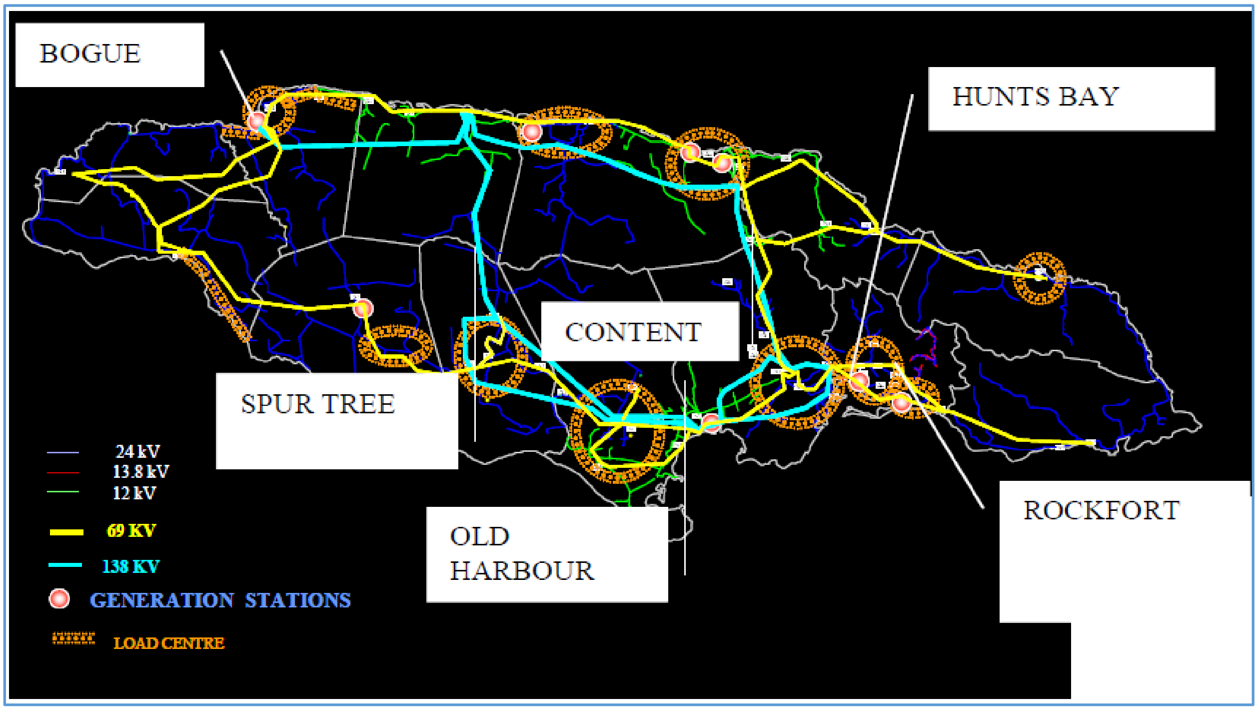
Prior to the incident, electricity to the customers was being supplied from an aggregate functional generation capacity of approximately 941 MW of which 250 MW is provided by IPPs with thermal plants supplying dependable capacity, while 119 MW is provided by IPPs with energy-only arrangements. The remaining 572 MW of this useful capacity is owned and operated by JPS. Details of the System's generation capacity is shown in Table 2.1 below.

Since the start of 2016 to date, the System peak recorded by JPS is 655.8 MW (occurred 2016 September 29) with an average System load factor of approximately seventy-five percent (75%). The previous reported System peak was 655.6 MW which occurred 2016 May.

2.5 JPS System Configuration

The Jamaican electric power system is an interconnected power grid linking four (4) major conventional power generation facilities and three (3) major renewable energy (RE) based power generation facilities in the west, south central and east areas of the island through 138 kV and 69 kV transmission systems, in which electric power is generated and transmitted at 50 Hz. The geographical layout of the Power System is shown in Figure 2.4 below.

Figure 2.4: Geographical Layout of the Jamaican Power System



Source: JPS 2016 August 27, Major System Failure Report

2.5.1 Generation Facilities

2.5.1.1 JPS' Generation facilities

JPS generates electricity using: steam (oil-fired), simple-cycle gas turbine, combined-cycle gas turbine (CCGT), slow speed diesel (SSD), hydropower, and wind power generation technologies.

The thermal power generating units are located at four (4) main sites in Jamaica, namely: Rockfort and Hunts Bay in Kingston, Old Harbour Bay in St. Catherine, and Bogue in St. James.

JPS' renewable energy (RE) generation facilities include, six (6) hydroelectric plants independently sited across the Island and a small wind power plant (3 MW) at Munro in St. Elizabeth. A description of the generation facilities is provided in Table 2.1 below.

2.5.1.2 IPPs Generation Facilities

IPP generation facilities supplying dependable capacity to the System are located at Rockfort, Marcus Garvey Drive, and Old Harbour, while those supplying electrical energy to the System on an as-available basis are located at Content Village in Clarendon, Rose Hill in Manchester, and Malvern in St. Elizabeth.

Table 2.1: System Functional Generation Capacity

Functional Generation Capacity of the Electricity System					
Owner/ Operator	**Site**	**Type**	**Installed Capacity [Functional] (MW)**	**Available Capacity 2016 Aug 27 (MW)**	**Remarks**
JPS	OLD HARBOUR		**193.50**	**126**	
	Unit#2	Steam	60.00	00.00	Major Overhaul 2016 (Jul 30 - Sep 4)
	Unit#3	Steam	65.00	60.00	
	Unit#4	Steam	68.50	66.00	
	ROCKFORT		**40.00**	**40.00**	
	RF#1	SSD	20.00	20.00	
	RF#2	SSD	20.00	20.00	
	HUNTS BAY		**122.50**	**122.50**	
	HB B6	Steam	68.50	68.50	
	GT#5	Gas Turbine	21.50	21.50	
	GT#10	Gas Turbine	32.50	31.00	
	BOGUE		**191.50**		
	GT#3	Gas Turbine	21.50	20.50	
	GT#6	Gas Turbine	18.00	14.00	
	GT#7	Gas Turbine	18.00	18.00	
	GT#8	Gas Turbine	**O/S**	**O/S**	Not Functional – Excluded from Rate Base (2014/19 DET NOTICE)
	GT#9	Gas Turbine	20.00	20.00	
	GT#11	Gas Turbine	**O/S**	**O/S**	Not Functional – Excluded from Rate Base (2014/19 DET NOTICE)
	CCGT	Combined- Cycle	114.00	114.00	
	HYDROS		**22.04**	**13.12**	
	Maggotty Hydro B	Hydroelectric	6.37	5.84	
	LWR	Hydroelectric	4.70	1.35	
	UWR	Hydroelectric	3.60	1.11	
	Roaring River	Hydroelectric	4.10	3.01	
	Rio Bueno A	Hydroelectric	2.50	1.31	
	Constant Spring	Hydroelectric	0.77	0.50	
	WIND (Munro)	Wind Power	**3.00**	0.31	
JPS Total			**572.54**	**486.93**	
IPPs (Firm Capacity)			**249.86**	**220.40**	
JPPC	ROCKFORT	SSD	60.00	60.00	
JEP	OLD HARBOUR	MSD	124.36	105.82	
WKPP	MARCUS GARVEY DR.	MSD	65.50	54.58	
JAMALCO	HALSE HALL	COGEN (Steam)	00.00	00.00	Contracted for 11MW. Cap constraint due to altered Configuration
IPPs "Wind & Solar" (Energy –Only)			**119.00**	**35.40**	
WWFL	ROSE HILL	Wind Power	62.70	31.30	
BMR	MALVERN	Wind Power	36.30	4.10	
Content Solar	CONTENT VILLAGE	Solar PV	20.00	0.00	
TOTAL			**941.40**	**742.73**	

2.5.2 Transmission and Distribution System

The Transmission and Distribution (T&D) System is comprised of approximately 14,000 km of power lines and forty-three (43) substations. The system is supported by twelve (12) 138/69 kV inter-bus transformers with a total capacity of 798 MVA and fifty three (53) 69 kV transformers (total capacity of 1026 MVA). The primary Distribution System is comprised of a network of 24 kV, 13.8 kV and 12 kV power lines (distribution feeders).

Standard conductors, mostly of dimensions 595 MCM and 394.5 MCM, are used throughout the transmission system. Varied sizes of conductors are used on the distribution systems.

2.6 System Operation

The Power System requires a level of centralized planning and operation to ensure System reliability and coordination. The System Operator at the Control Center carries out many of these centralized functions in support of System operations, including short-term monitoring, analysis, and control.

2.6.1 Reliable Operation

The reliability of a Power System is a measure of its ability to satisfy its intended function which is to supply uninterrupted power under normal and credible conditions on a continuous basis.

There are two elements to System reliability; adequacy and security. System adequacy refers to the ability of the Power System to meet customer load demand and is associated with steady state conditions. In contrast, System security relates to the ability of the Power System to deal with disturbances and return to a steady state operational condition.

Maintaining reliability is a complex and demanding task that requires trained and skilled personnel, sophisticated computers and communications, and careful planning and design. In the Jamaican electricity sector, the legal and regulatory framework dictates that applicable standards/procedures for System operation & planning must be in place for ensuring the reliability of the electricity System. These requirement are usually guided by the following key concepts:

- Balance power generation and demand continuously.
- Balance reactive power supply and demand to maintain scheduled voltages.

- Monitor power flows over transmission lines and other facilities to ensure that thermal and capacity limits are not exceeded.
- Plan, design, and maintain the System to ensure reliable and stable operation, taking into account contingency conditions, such as the loss of a key generating plant or transmission line or equipment (the "N-1 contingency criterion").
- Prepare for operation during System emergencies.

The electricity supply industry (ESI) over time has developed a set of reliability standards and best practices to ensure that System Operators are prepared to deal with exceptional circumstances during System operation. The basic assumption underlying these standards and practices is that Power System elements at some point may fail or become unavailable in an unpredictable manner. Effective reliability management is designed to ensure that safe and continuous operation can be achieved following the unexpected loss or disruption of any key component of the System. These practices have been established to maintain a functional and reliable power grid, whether actual operating conditions are normal or abnormal.

In summary, a properly planned Power System should take into account the following aspects:

- Adequacy – normal and contingency
- Maintenance – effective, efficient, suitable and flexible
- Safety and Protection
- Recovery – restoration

2.6.2 System Operating Criteria

To ensure that the System operates in a safe and reliable manner under normal and contingency conditions, operation parameters and security limits for the interconnected System must be established and codified.

2.6.2.1 Dispatch Requirements

As required by the Licence, JPS shall schedule and issue direct instructions for the dispatch of the available generating plants to generate or transfer electricity:

a) in ascending order of the marginal costs in respect of any hour for the generation and delivery or transfer of electricity into the System, to the extent allowed by transmission system operating constraints based on "equal Incremental Cost-System" principles; and

b) as will, in aggregate and after taking into account electricity delivered into or out of the System, from or two other sources, be sufficient to match at all times (so far as possible in view of the availability of the Generation Sets) demand forecast taking into account information provided by authorised electricity operators, together with an appropriate margin of reserve for security operation.

The dispatch instructions shall be subject to the following factors:

i) forecast demand (including transmission and losses and distribution losses);
ii) economic and technical constraints from time to time imposed on the System or any part or parts thereof;
iii) the dynamic operating characteristics of available Generation Sets; and
iv) other requirements provided for in the Generation Code,

2.6.2.2 System Security Standards

As stipulated in Clause 3.4.1 of the Generation Code (2013), which was in effect at time of the incident, the System Operator shall carry a minimum Spinning Reserve margin of 30 MW as set out in Schedule D of the Code. The determination of the Spinning Reserve margin shall be based on economics and System Security considerations.

This has been established as the balance between economy and maintaining System security. The actual spinning reserve margin is the excess of generating capacity on-line above the System peak load at a point in time.

2.6.2.3 Operating Performance Standards

System Frequency

Pursuant to section 1.3 (i) of the Generation Code (2013), the normal operating frequency of the System Grid shall be controlled by the System Operator to be within 50.0 Hz ± 0.2 Hz.

Generating units shall be designed for sustained operation within the frequency limits specified in Clause 1.2.2 (i) of the Generation Code (2013) (frequency range of 49.5 Hz to 50.5 Hz), and for restricted time based operation within the emergency frequency limits as specified in Clause 1.2.2 (ii) of the Generation Code (2013) (frequency range of 48.0 Hz to 52.5 Hz).

System Voltages

Regarding the requirements for System voltages under normal and contingency conditions, section 1.3 (ii) of the Generation Code (2013), provides as follows:

The normal operating voltages of the System shall be within:

a) ± 5 % at the generator Bus;
b) ± 5 % on the transmission system;

The contingency (abnormal) operating voltages shall be within:

a) ± 5 % at the generator bus;
b) ± 10 % on the transmissions system

Short Circuit Levels

As stipulated under section 1.3 (iii) of the Generation Code (2013), the System shall be designed to withstand a three phase symmetrical short circuit at the Generating Unit Substation for fault levels as specified in the appropriate Technical Standards as set out in Clause 1.2.1 of the Generation Code (2013).

Transmission Line Thermal Rating

Under contingency conditions, transmission line loading of up to 110% of rated continuous rating for 30 minutes (Emergency Rating) may be used. The System operating limits are outlined in Table 2.2.

Table 2.2: System Operating Limits

System Operating Limits	
SYSTEM PARAMETERS	**LIMIT**
Voltage	+/- 5% of nominal voltage for normal operation and +/- 10% for contingencies
System Frequency	50 Hz +/- 0.2 Hz
Generator Frequency	Normal operating limit of 49.5 Hz to 50.5 Hz Operating range of 48.0 Hz to 52.5 Hz
Line Thermal Limit	Line loading should not be greater than 110% of thermal rating for 30 minutes.

JPS Electrical Sub-systems

The JPS electricity System can be divided into two (2) electrical sub-systems - the Corporate Area (CA) and Rural Area (RA) sub-systems.

2.7 Protection and Control System

2.7.1 Protection Philosophy

According to JPS, its protection philosophy requires the main/primary protection deployed on the Power System to clear all faults, with additional levels of redundancy provided by back-up protection schemes to ensure reliable operation of the System.

2.7.2 Protection Design

The design principles of the protection system should normally include the following:

- The primary distance protection relays must have 100% equipment redundancy (A&B) and perform the dual function of providing main protection for the transmission lines by means of its zone 1 and zone 2 reach elements and remote back-up for faults on the next in line circuit by means of its zone 2 and zone 3 elements.

- Primary "A" distance protection relays must be supplied by separate current transformers (CTs) while primary "B' distance and back-up protection schemes are normally supplied from the same CT core. The primary "A & B" protection auxiliary DC power supplies should be 100% separated to minimize the likelihood of failure on both relays.

- The same voltage transformer (VT) is normally used for A and B circuits except the primary "A" protection scheme which must be supplied by separate secondary windings while primary "B" can share the secondary windings with the back-up protection. Where only one secondary winding exists each protection should be separately fused.

- Back-up protection is divided into two groups: (a) local backup where secondary protective devices on the faulted circuits operate to interrupt the fault following non-operation of the main protection and/or its associated circuit breakers; and (b) remote backup, where faults are cleared from the remote busbar.

2.7.3 Protection Design Objectives

The basic design objectives of the protection system are to: (a) maintain dynamic stability of the System, (b) prevent or minimize equipment damage, (c) minimize equipment outage time, (d) minimize System outage area, (e) minimize System voltage disturbances, and (f) allow the continuous flow of power within the emergency ratings of equipment on the System.

2.7.4 Protection Design Criteria

To accomplish the design objectives of the protection system, four main criteria are considered: speed, selectivity, sensitivity and reliability (dependability and security).

2.7.5 Protection for JPS Transmission Lines

At each transmission line terminal (i.e. substation or switchyard), the following protective relaying systems are provided, with relay settings as indicated.

Primary "A" Distance Protection

A primary distance relay is utilized in conjunction with a digital-microwave communication channel and POTT (permissive overreaching transfer-trip) logic for high-speed fault clearance over 100% of the protected line. Overreaching of the remote line terminal is prevented by communication between the pilot relays at both line terminals. The communication path is a redundant communication link of either fibre optic or digital microwave. The primary distance relay also provides time-stepped backup protection, independently of the communication channel.

Details of the primary "A" protection scheme and settings are provided below:

- Zone 1: High-speed clearance for 80-90 % of the protected line. For 138 kV lines terminating into Inter-bus or distribution power transformers, the zone 1 reach setting is modified to 110 % of the protected line.

- Zone 2: Delayed protection for 100 % of the protected line plus 50 % of adjacent line, with operating time delay of 0.4 second. For 138 kV lines terminating into Inter-bus transformers, the zone 2 reach setting is modified to 100 % of the protected line plus 50% of the transformer impedance.

- Zone 3: The zone –3 element in the primary "A" distance relay is a reverse-looking element required for the permissive overreaching transfer trip (POTT) scheme logic – it is not utilized for tripping.

- Zone 4: Delayed protection for 100 % of protected line plus 120 % of adjacent line, with operating time delay of 0.8-1.0 second. For 138 kV lines terminating into Inter-bus transformers, the zone 4 reach setting is modified to 100 % of the protected line plus 120 % of the transformer impedance.

NOTE: Pilot protection is not applicable to radial transmission lines; therefore, for these lines, only the duplicate primary or backup distance relay is provided.

Redundant Primary "B" Distance Protection

A redundant (or duplicate primary) distance relay is utilized to provide 3-zone time-stepped distance protection independently of a communication channel or with communication channel, as outlined below. The primary and backup distance relays are of different make to ensure that both relays do not fail at the same time due to any common design deficiency. The communication path is a redundant communication link of either fibre optic or digital microwave.

Details of the primary "B" protection scheme and settings are provided below:

- Zone 1: High-speed clearance for 80-90 % of the protected line. For lines terminating into transformers (Inter-bus or distribution), the zone 1 reach setting is modified to 110 % of the protected line.

- Zone 2: Delayed (0.4 second) backup protection for 100 % of protected line plus 50 % of adjacent line. For lines terminating into transformers (Inter-bus or distribution), the zone 2 reach setting is modified to 100 % of the protected line plus 50 % of the transformer impedance.

- Zone 3: is used as a reverse looking element in the POTT scheme and is not used for tripping.

- Zone 4: Delayed (0.8-1.0 second) backup protection for 100 % of protected line plus 120 % of adjacent line. For lines terminating into transformers (Inter-bus or distribution) the zone 4 reach setting is modified to 100 % of the protected line plus 120 % of the transformer impedance.

<u>Back-up Directional Over-current Protection</u>

Directional over-current relays with both instantaneous and time-delayed characteristics are provided for backup fault clearance. At some locations, this function is obtained via the backup distance relay. Setting criteria are as follows:

- The instantaneous pickup setting is typically 125% of maximum fault current flow from the relay location for a fault at the remote busbar, to prevent overreaching and hence mis-coordination.

- The time-delayed phase-fault pickup setting ranges between 90-110% of line rating.

- The pickup setting for the time-delayed ground-fault element is 20-30% of the corresponding phase-fault pickup setting.

- A minimum coordination time of 0.4 seconds is the benchmark requirement for relay pairs (i.e., for two relays in series)

2.7.6 Protection Schemes for the Hunts Bay – PAJ 69 kV Transmission Line

The protection schemes installed at Hunts Bay substation for the protection of the Hunts Bay - PAJ 69 kV line which were required to operate and clear the solid three phase-to-ground fault on 2016 August 27, are:

1) Enhanced Primary “A” high-speed Switch-Onto-Fault (SOTF) non-voltage dependent protection with operating speed of within 100 ms.

2) Back-up definite time directional overcurrent voltage dependent protection with time delay of 250 ms.

3) Primary “A” delayed zone 2 distance protection with operating delay of 400 ms.

4) Primary “B” delayed zone 2 distance protection with operating delay of 400 ms.

5) Back-up directional overcurrent low-set inverse time delay with simulated operating delay of approximately 580 ms.

An inherent design feature of the 69-kV breaker-and-a-half configuration at Hunts Bay and similarly configured stations is that VTs, are located on the lines. Accordingly, when these lines are being energized, the VTs are energized at the same time and do not provide prior voltage sensing for the voltage dependent protections. For this scenario, voltage dependent protection will be subjected to a time delay of 10 ms or less before these VTs can magnetize and reproduce the voltage required by these protections. To address this design feature, the non-voltage dependent SOTF scheme is employed and is activated by a change of state from "open" to "close" of the circuit breaker via its auxiliary "a" contact. Once activated by the breaker change of state, the presence of a high current due to faults will initiate tripping of the associated circuit breakers.

2.7.7 Under-frequency Load Shedding Scheme

In instances of generation-load imbalance when there is a sudden increase in load or a generating unit trips off-line, automatic Under-Frequency Load Shedding (UFLS) is employed to restore the generation/load balance and maintain nominal frequency by disconnecting equal or more load than the equivalent of the excess demand. Loads are shed in five (5) stages as shown in Table 2.3, and a time delay setting of 0.15 seconds is used to override transients. The scheme functions to give the operator enough time to respond and take corrective action by facilitating a temporary recovery in frequency, this recovery may manifest in two ways: (1) If there is an over-shed and the settling frequency is too high then the operator is required to add load; and (2) if insufficient load is shed and the settling frequency is low, the operator is required to shed additional loads. Other considerations that form the basis of the scheme design include:

- The operating times of relays and circuit breakers
- The set and reset frequencies for different stages as well as the amount of load shed per stage, and the frequency at which the System settles down
- The reliability of the scheme as it relates to the dispersion of the under frequency relays
- The safe operating frequency of generating units

Table 2.3: UFLS Stages and Settings

Current Setting of Under-Frequency Relays	
Stage	**Under-Frequency Relay Setting (Hz)**
0	49.35
1	49.20
2	48.90
3	48.50
4	48.10

2.8 Remote Control and Communication Systems

2.8.1.1 SCADA/EMS System

The Supervisory Control And Data Acquisition (SCADA) system provides real-time monitoring and control of the transmission grid and it consists of a master station at the System Control Center and multiple Remote Terminal Units (RTUs) at remote stations island-wide.

The RTUs collect analog and status data from field equipment such as breakers and transformers automatically and stores it in a buffer until the master station interrogates these remote units via the communications link to acquire the data.

At the master station, the data is stored and a predefined set of data is displayed graphically and in tabular form. The SCADA system allows the System Control personnel to be able to view the status of System equipment/apparatus, remotely operate circuit breakers and switches and to read telemetered data from the System Control Room. The critical components of the SCADA system are duplicated to provide a high level of reliability.

The Energy Management System (EMS) is a high performance network and generation analysis system that utilizes the real-time telemetered data from SCADA for real-time System optimization and to improve operator awareness. The EMS supplies operational personnel with a suite of information management tools that allows them to visualize and respond to ever-changing System conditions.

2.8.1.2 Communication System

The JPS Communications Network consist of both a Digital Microwave Network (island-wide) and a Fibre Optic Network in all Parishes except St Mary, Portland and St Thomas. This provides the transmission medium for JPS's internal communications including SCADA, voice and data traffic.

The SCADA system uses both the Digital Microwave and Fiber network for communicating with the SCADA/EMS system at System Control. For the areas of the island where no fiber exists, the Digital Microwave system is used as the primary communication medium and a mixture of analog and PLC equipment is used as backup for SCADA.

2.9 System Control

The System Control Center is currently located in Kingston, Jamaica, from which the System Operator monitors and controls the System. The Control Center is supported by the SCADA system that report the status of circuit breakers—open or closed—as well as voltage, current, and power levels.

The functions performed by the System Control Center includes:

Monitoring

This involves the use of various displays and alarms by the System Operator to be aware of the state of the System at all times.

Analysis

Raw data reported to System Control Center are analyzed by the EMS which can give insight on the current state of the System and can also be utilized to predict the future state of the System.

Control

This function broadly involves the control of the generation, transmission and distribution of electrical energy throughout the System.

2.10 System Planning

In terms of day-to-day planning, the System Operator is required to analyze the System and adjust the planned outages of generating units and transmission lines so that if a System component unexpectedly becomes unavailable, the remaining System should still be able to operate within the required operating limits.

In terms of real-time operations, the System must be operated at all times to be able to withstand the loss of any single network element or facility and still remain within thermal, voltage, and stability limits. If a network element or facility experiences a forced outage, the System Operator must take the necessary actions to ensure that the remaining System is able to withstand the loss of yet another key element and still operate within the required operating limits.

In addition to the day-to-day planning and operation of the System, its long-term health is a separate issue that System planners generally address through appropriate medium and long-term planning approaches.

3 STATUS OF THE POWER SYSTEM PRIOR TO SHUTDOWN

3.1 Overview

This chapter focusses on the state of the System prior to 2016 August 27 and up to 5:45 pm EST on August 27 to determine whether conditions at that time might have contributed to the complete System shutdown.

Prior to removal of the Hunts Bay – PAJ 69 KV line from service and the sectionalizing of the PAJ 69 kV busbar to facilitate JPS' planned maintenance works, it was found that a contingency impact assessment of the maintenance outage was carried out by the JPS to ascertain the effects of the outage on the System and any mitigating measures to be taken to reduce any adverse impact of the "N-1" contingency and any subsequent "N-1-1" contingency on the network.

At 5:45 pm EST, immediately before the switching operation to re-energize the Hunts Bay – PAJ 69kV line to return it to normal operation, the prevailing conditions suggest that the System was experiencing a few constraints but could still serve the projected System demand even under the existing contingency condition.

Establishing that the System was in a reliable operational state at the time of the incident is extremely important to understanding the causes of the blackout. This essentially eliminates the possibility that pre-existing electrical conditions on the System before 5:45 pm EST was a direct cause of the power blackout. It also eliminates a number of possible causes of the blackout, whether individually or in combination with one another, such as, power export/import imbalances, intolerable System frequency variations, voltage related problems, reactive power concerns, unavailability of generating units and/or transmission lines, etc.

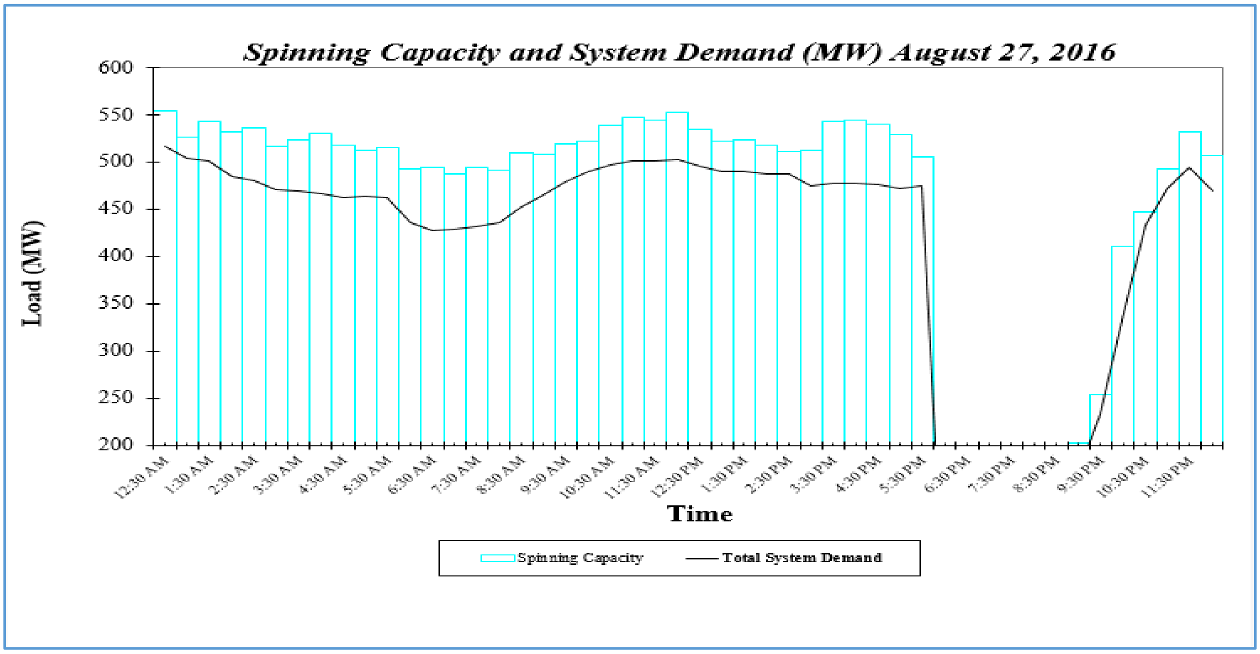
Notwithstanding, it is important to emphasize that establishing whether conditions were normal or abnormal prior to and on 2016 August 27, does not relieve the System Operator of its responsibilities and obligations for ensuring that the System is maintained and operated in a safe and reliable manner.

3.2 System Operational State Prior to Shutdown

3.2.1 System Demand Profile on August 27

According to the "Technical Report", at the time of the incident, there was fair weather conditions, and there was no indication that temperature levels were above normal. The reported System demand was 481.68 MW which was representative of a typical Saturday afternoon 5:00 – 6:00 pm load. The recorded hourly System demand leading up to the time of the incident were within normal range and were not considered to be unmanageable. The generation capacity available to serve the load at the time was approximately 590 MW. The System demand profile for 2016 August 27 is shown in Figure 3.1.

Figure 3.1: System Demand Profile – 2016 August 27



Source: JPS 2016 August Technical Report

3.2.2 Available Generation Capacity on August 27

Table 3.1 below shows the total System demand, the available capacity and dispatch level of each generating unit online and the spinning reserve margin on 2016 August 27 at the time of the incident.

Table 3.1: Generating Units Online and Dispatch Level at the time of the Incident

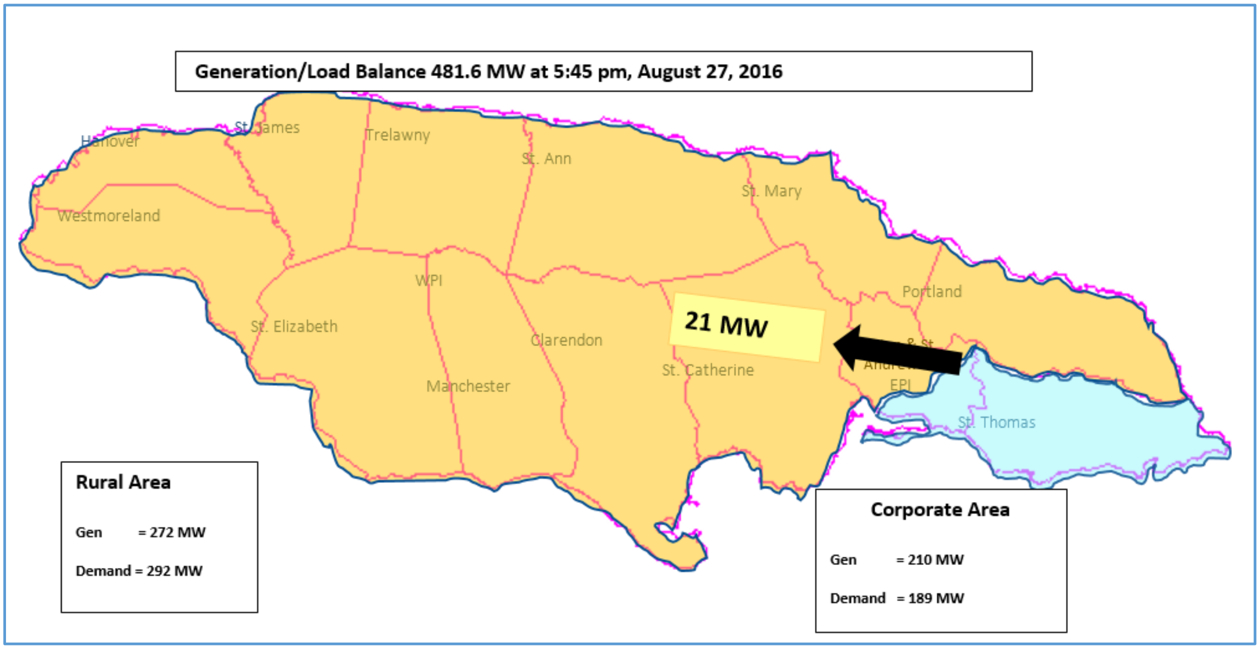
Generating Units Online and Dispatch Level at the time of the Incident			
Generating Units	**Available Capacity (MW)**	**Dispatched Capacity (MW)**	**Reactive Power Level (MVAr)**
OH Unit 3	60	55.48	35.11
OH Unit 4	66	58.65	26.21
HB Unit B6	68.5	58.07	10.72
RF Unit 1	20	18.97	0.77
RF Unit 2	20	20.45	2.03
Bogue CCGT	114	102.82	10.64
JPPC	60	57.17	2.95
JEP	105.82	32.8	16.6
WKPP	54.58	55.4	15.7
JA Broilers	1.91	1.91	0
WWFL 1&2	3.51	3.51	4.73
WWFL 3	2.05	2.05	1.43
ROARING RIVER	3.01	2.94	0
UWR HYDRO	1.11	1.1	0.98
LWR HYDRO	1.35	1.4	-0.26
MAGGOTTY HYDRO 6.37MW	5.84	6.48	0.30
RIO BUENO A	1.31	1.26	0.63
CONST. SPRING HYD	0.5	0.41	
BMR	0.75	0.75	0.34
TOTAL	**590.24**	**481.68**	**128.76**
Total System Demand (MW)		**481.68**	
Available Capacity (MW)		**590.24**	
Reserve Capacity (MW)		**108.56**	
Spinning Reserve (MW)		**25.07**	
Frequency (Hz)		**49.88**	

Data source: Technical report (2016 September 28) and JPS' GPCRs (2016 August 27)

According to the GPCRs for 2016 August 27 (7:00 am and 3:00 pm), the available capacity at the JEP generation complex was reported to be 105.82 MW but was only dispatched to 32.8 MW. However, JEP's Report to JPS on the shutdown indicates that the available capacity at the complex at the time of the incident was 115.09 MW.

As shown in Table 3.1 above, the total generation capacity available at the System Operator prior to the incident was 590.24 with a reserve of 108.56 MW. This capacity could be committed to ensure that the relevant System's security limits were satisfied.
The generation/load balance at 5:45 pm, 2016 August 27, 2016 is illustrated in Figure 3.2 below.

Figure 3.2: Generation/Load Balance at 5:45 pm, August 27, 2016



3.2.3 Spinning Reserve

Based on the available generation capacity online relative to the System demand just before the incident, the spinning reserve margin was **25.07 MW**. This was a clear violation of the spinning reserve requirements stipulated by the Spinning Reserve Policy set out under Schedule D of and the Generation Code (2013), applicable at the time (Refer to Figure 3.3 below). Subject to these requirements, JPS is required to plan and operate the System with a minimum spinning reserve capacity of 30 MW to meet the daily System demand.

Figure 3.3: Spinning Reserve Policy for JPS

SPINNING RESERVE POLICY:

SYSTEM OPERATION POLICIES AND PROCEDURES

CLIENT: JAMAICA PUBLIC SERVICE COMPANY LIMITED — Ref. No. 8 Page: 1 of 1

SUBJECT: OPERATING SPINNING RESERVE POLICY — Effective Date:________

	Responsibility	Reference
The following details the company's spinning reserve policy.		
A minimum spinning reserve capacity of 30 MW should be planned to meet the daily system demand.	Operation Planning Engineer	
Consistent with the above policy, the following measures should be adopted:		
a) The Old Harbour units (OH2, OH3, OH4) and Hunts Bay B6 steam unit are to be limited to a maximum of 85% of their Maximum Continuous Rating (MCR). The difference between the reserve allocated by the above restrictions and the stipulated 30 MW operating spinning reserve is to be allocated across the system by means of an economic optimization process.	System Control Engineer	
b) Under normal circumstances a gas turbine should not be started with the spinning reserve above 30 MW. However, if the margin should fall below 30 MW, a gas turbine can be used to assist in maintaining a margin of spare plant.	System Control Engineer	Section 7.2
c) Gas Turbines should be used for quick load restoration following operation of under frequency relays. (At least two of the aeroderivative GTs (GTs 6, 7, 8, 9, 11) should be on remote standby for this purpose, unless they are required to meet the demand.	System Control Engineer/Bogue Operations Manager	
d) No single generator should be allowed to carry more than 27.7% of the total demand. This is in keeping with the system overload protection of 38%. Provisions for this is made in the ELD programme.	Operations Planning Engineer/System Control Engineer	

Approved By	Status	First Effective	Supercedes	Reviewed By
[signature]	Active	Dec 2006	Apr 03	Ricardo Case

4/09/05

Source: Generation Code (2013) and Jamaican Electricity Sector Book of Codes (2016 August 29)

The generation information provided in JPS' Gross Plant Capability Reports (GPCRs) for 2016 August 27 (7:00 am and 3:00 pm) indicated that there was adequate capacity available to the System Operator to ensure that the stipulated minimum spinning reserve capacity was satisfied.

According to the said GPCRs, JEP (OH) had 105.82 MW of capacity available from six (6) units on Barge #1 and three (3) from Barge #2 but only two (2) units (#9 and #11) were dispatched by the System Operator to supply 32.8 MW to the System. This indicates that even with the planned transmission outages and the generation capacity constraints described in section 3.2.6 and

3.2.7, suitable options were available to the System Operator to meet the spinning reserve requirement.

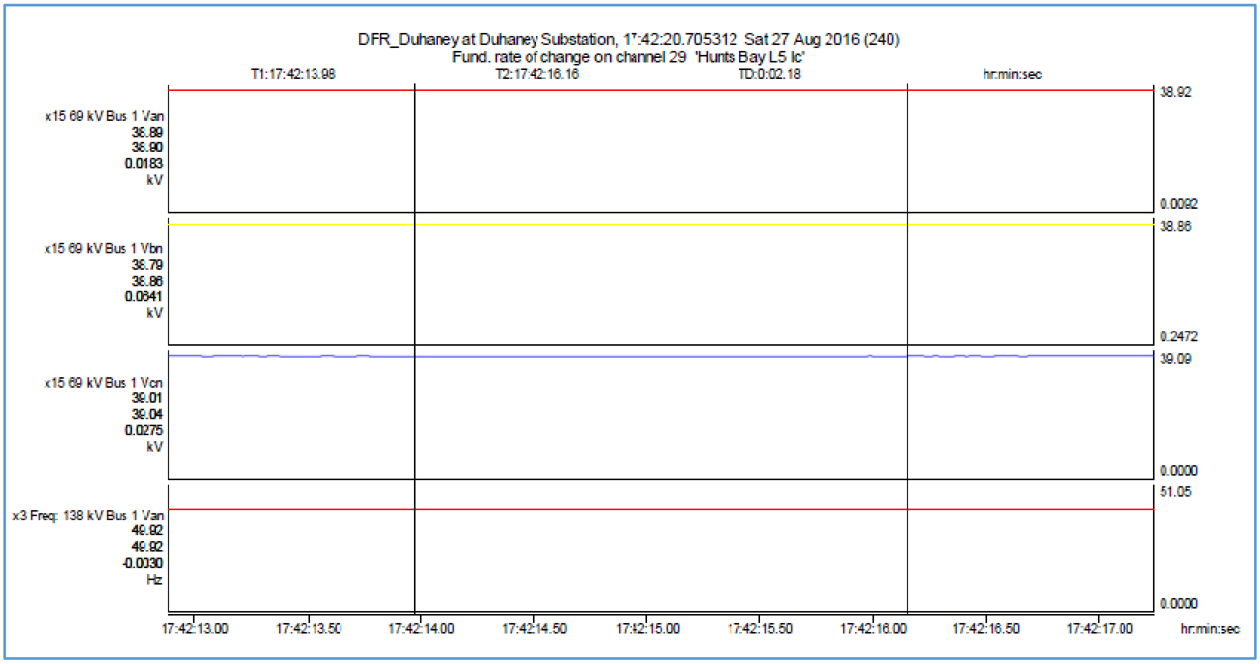
The generation information provided also indicated that the spinning reserve capacity on the System at the time may not have been optimally distributed across the generating units online. These observations raise concerns as to whether the System is being planned and operated in conformance with the relevant System security requirements.

3.2.4 System Frequency

The Jamaican Power System operates at a frequency of 50 Hz. This operating frequency is typically achieved when the load being served is exactly balanced with active power generated. In instances of loss of active power generating capacity without a corresponding loss of active load, System frequency will decline commensurate with the level of System overload. In order to maintain the load/generation balance, when System frequency declines, the System relies on automatic under-frequency load shedding to reduce the loads. In instances where the active power generation is greater that System load, the generating units' frequency regulation mechanisms respond to maintain the System frequency at 50 Hz.

On 2016 August 27 up to 5:45 pm, the System frequency recorded by Digital Fault Recorder (DFR) located at JPS' Duhaney substation was 49.92 Hz (Refer to Figure 3.4). This frequency level was within the normal operating range of 50.0 Hz ± 0.2 Hz as specified by the Generation Code. As such, System frequency variation did not create any undue adverse conditions at the commencement of the power blackout. However, once the cascading events were initiated, the resulting large and uncontrollable variations in System frequency that ensued, compounded the situation, consequently leading to the total collapse of the System.

Figure 3.4: System Voltage and Frequency on August 27 up to 5:45 pm



Source: JPS Major System Incident Technical Report - dated 2016 September 28 (Section 5.1.1, page 16)

3.2.5 System Voltage

On 2016 August 27 up to 5:45 pm, the voltage, as recorded by the DFR located at JPS' Duhaney substation, was: Phase A – 38.89 kV; Phase B – 38.79 kV; Phase C – 39.01 kV. These translate to line voltages of approximately 67.5 kV, which were within the limits of ± 5% of nominal operating voltage on the transmission system as required by the Generation Code. Unlike frequency, which is constant across the network, the voltage at different locations on the network can vary. For that reason, the System Operator is required to monitor voltages continuously to ensure that they are within the specified limits. It was also observed that a significant portion of the reactive power requirements for the System was being provided by Old Harbour Units #3 and #4.

3.2.6 Unavailable Generation Capacity Prior to Incident

Based on information provided in the "Technical Report" and supplementary data, two of the major generating units in the System were out of service before the incident occurred. JPS' OH Unit #2 was on Major Overhaul that started 2016 July 30 and projected to return to service on 2016 September 4. This unit is capable of providing reactive power and spinning reserve to support stable and reliable operation of the power grid.

WKPP DG #4 was also out of service on planned outage and was due to return to service 2016 August 30.

According to the GPCRs for 2016 August 27 (7:00 am and 3:00 pm), several key generation plants were subject to unplanned forced capacity derating due to various technical problems. It should be recognized that some of these affected generating units are capable of providing reactive power and spinning reserve to support stable and reliable operation of the power grid. The overall effect of the constraints on these generating units could have been an adverse factor to the generation system performance during the outage.

Table 3.2: Unavailable Generation Capacity – August 27

Unavailable Generation Capacity Prior to the System Incident									
Plant/ Unit	**MCR (MW)**	**Avail-able (MW)**	**Short-fall (MW)**	**Cause of Unavailable Capacity**	**Event Type**	**Effective Date**	**Effective Time**	**Expected Return Date**	**Expected Return Time**
GT#10	32.50	31.00	1.50	Degradation of turbine compressor	D1-Unplanned (forced) derating - immediate	2016 Aug 22	11:34am	NO DATE GIVEN	NO TIME GIVEN
OH#2	60.00	0.00	60.00	Major Overhaul	U1-Unplanned forced outage - immediate	2016 Jul 30	8:00am	2016 Sep 4	2:00pm
OH#3	65.00	60.00	5.00	Boiler low air flow	D1-Unplanned (forced) derating - immediate	2016 Aug 08	4:50pm	NO DATE GIVEN	NO TIME GIVEN
OH#4	68.50	66.00	2.50	Low Condenser Vacuum	D1-Unplanned (forced) derating - immediate	2016 Aug 25	2:00pm	NO DATE GIVEN	NO TIME GIVEN
BO GT#3	21.50	20.50	1.00	Worn Compressor	D1-Unplanned (forced) derating - immediate	2016 Aug 19	8:16pm	NO DATE GIVEN	NO TIME GIVEN
BO GT#6	18.00	14.00	4.00	Smaller engine Installed	D1-Unplanned (forced) derating - immediate	2015 Feb 15	2:20pm	NO DATE GIVEN	NO TIME GIVEN
JEP	124.36	105.82	18.54	DG #2 on forced, Dg#1 on planned	Unplanned (forced) derating - immediate	2016 Aug27	12:55am	2016 Aug 27	6:00pm
WKPP	65.50	54.58	10.92	DG#4 on planned	PD-Planned derating	2016 Aug 27	12:01am	2016 Aug 30	12:01am
JPPC	60.00	60.00	-	DG#2 on forced Outage	D1-Unplanned (forced) derating - immediate	2016 Aug 27	1:00am	2016 Aug 27	NO TIME GIVEN

Source Information: JPS GPCRs for 2016 August 27 (7:00 am and 3:00 pm)

As indicated in Table 3.2, the unavailable generation capacity prior to the outage was as follows:

1) 60 MW - major overhaul of OH Unit#2
2) 10.92 MW - WKPP DG #4 out of service on planned outage
3) 9.27 MW – JEP DG#1 on planned outage
4) 9.27 MW - JEP DG#2 on forced outage
5) 14 MW – unplanned forced derating

The operation of the System with such level of unavailable capacity, with anticipated Saturday peak load of over 600 MW, depicts an operating scenario of diminished operating capacity reserve and the likelihood of loss of load.

It is worth noting that in the GPCRs for 2016 August 27 (7:00 am and 3:00 pm), JPS indicated that the major overhaul of OH Unit#2, was necessitated by an “unplanned forced outage”.

3.2.7 Transmission Network Outages Prior to Incident

Information provided in the System Control Report (Appendix D of the “Technical Report”), indicated that two (2) transmission outages were in progress prior to the incident:

1) Spur Tree - Parnassus 138 kV transmission line was isolated with a section of the bay-area at Spur Tree. JPS’ Regional Substation Maintenance Department (SMD) was doing remedial maintenance work in the bay-area and Regional Transmission Line Maintenance (TLM) was utilizing the outage to conduct maintenance on the transmission line. According to System Control, the isolation was done at 10:33 am and the outage was reported completed at 3:34 pm and the workmen left the location.

2) A section of the PAJ 69 kV substation including transformer T2 was de-energized and isolated at 9:55 am to carry out cleaning of the T2 transformer and to work on MOD 169/8-251 at the substation. This was a planned outage (JPS outage id#: P.A-2016-89-746).

3.2.8 Protection System Status

According to the “Technical Report”, prior to the fault, all line relays associated with Hunts Bay – PAJ 69 kV transmission line were available.

3.2.9 Network Visibility and Communication

The SCADA/EMS Report (Appendix E of the “Technical Report”) indicated that prior to the incident, the SCADA system was fully operational and available with all servers, peripherals and input and output devices performing as expected. Section 2.8 of the “Technical Report”, indicated that prior to the incident, all substations were observable via the SCADA system. However, the ECS Report (Appendix F of the “Technical Report”) indicated that there were issues with the SCADA system before the 2016 August 27 outage. JPS has indicated that the issues on the SCADA system pertains to communication pathways that were either intermittent or operated normally on their backup communication channels. However, the company claims that 'with the exception of the Port Antonio issue, there were no other pre-existing issue with the SCADA system' and 'the August 26 failure of the Port Antonio primary SCADA link did not impact SCADA functionality as the backup link worked as designed'.

3.2.9.1 SCADA Data Availability at System Control Centre

On page 4 of the ECS Report, under the heading "SCADA Data Availability at System Control Centre", JPS indicated that there were known issues before the grid outage 2016 August 27.

These issues as reported JPS are summarized in Table 3.3.

Table 3.3: Known Issues before 2016 August 27

SCADA Issues before 2016 August 27	
SITE	**STATUS**
Cement Company	The site was operating intermittently due to a damaged feed horn antenna. A replacement feed horn was sourced from inventory and replaced on 2016 August 29.
Jamaica Broilers	Failed radio at site and its repair was awaiting a replacement radio that was delivered on 2016 September 12
Port Antonio	The Primary SCADA link via Shotover repeater site failed on August 26 due to the supply leg on the JPS meter being burnt out. The secondary SCADA link used PLC and was operational.

Source: ECS Report (Appendix F of the JPS Major System Incident Technical Report - dated 2016 September 28)

3.2.10 System parameters Prior to Incident

The active and reactive data for the distribution feeders prior to the outage, were found to contain the following problems:

- Feeders active power (MW) with negative values
- Feeder points where active power (MW) readings were zero with no mention of an outage or explanation
- Feeder points where field updates were not available

The number of the observed irregularities associated with feeder data are shown in Table 3.4 below.

Table 3.4: Feeder data Issues

Item	Non-Update, Negative or Zero Readings	Total in Field	% Error
Feeder MW, MVAR	161	384	41.9
Branch MW, MVAR	41	607	6.8
Busbar Voltage	18	148	12.2

3.3 Summary

Determining that the System was in an adequate and reliable operational state at 5:45 pm on 2016 August 27 is fundamental to establishing an appropriate reference point for understanding the true causes of the subject power blackout. It is also important to establish that the System was in a normal operational state prior to the shutdown incident to ascertain that there was no prior electrical conditions active on the System that could be deemed to be a factor that influenced the power blackout.

While there were no clear evidence of major adverse pre-blackout conditions impacting the System, the fact is that the deficit in generation capacity due to unplanned circumstances and the spinning reserve situation cannot be ruled out as a constraining factor in the System's response to the incident on 2016 August 27.

4 CAUSES OF THE POWER BLACKOUT

This chapter explains the major events that occurred as the collapse of the System evolved on 2016 August 27, and identifies the causes that initiated the power blackout.

The main events which culminated in the 2016 August 27 All-Island power blackout, began at 9:00 am EST on August 27, the point at which JPS commenced planned maintenance works at the PAJ substation located in the CA. According to the “Technical Report”, the maintenance works involved the replacement of control panel for line disconnect switch 169/8-251, timing tests for breaker 169/8-430 main contacts and general cleaning of transformer T2 bushings.

JPS indicated that the planned maintenance works at the PAJ substation required an outage and involved the de-energization of the Hunts Bay – PAJ 69 kV line and sectionalizing of the PAJ substation 69-kV busbar.

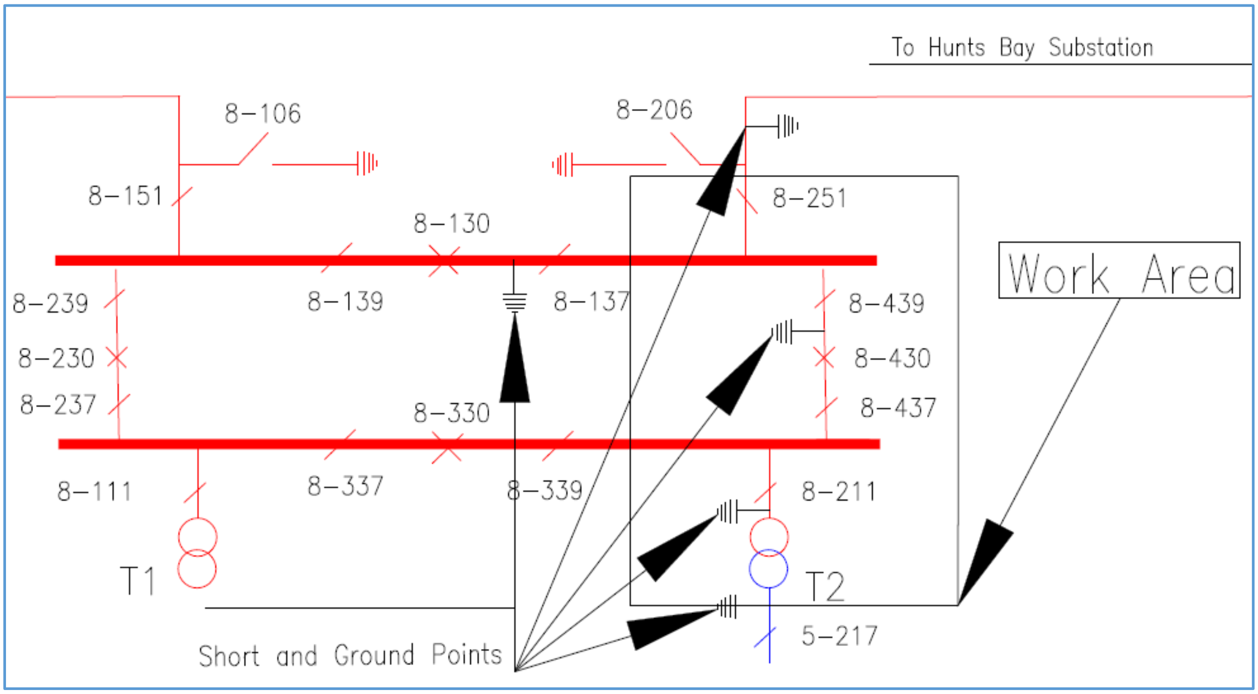
JPS also stated that added precautionary measures were taken as per its established safety procedures which necessitated the installation of five “short-and-grounds” at various points in the work area, to minimize the risk of serious injury to personnel if an inadvertent re-energization of the work area were to occur. In the “Technical Report”, JPS indicated that the “short-and-grounds” were installed as follows:

- One (1) on circuit breaker 169/8-130 bushing towards disconnect switch 169/8-139 – (#1)
- One (1) on circuit breaker 169/8-430 isolating switch 169/8-437 - (#2)
- One (1) on the HV terminal of transformer T2 - (#3)
- One (1) on the LV terminal of transformer T2 - (#4)
- One (1) on the line-side of disconnect switch 169/8-251 - (#5)

The T&D Report (Appendix D of the “Technical Report”), however, indicated slight discrepancies with these placements. The T&D report indicated that “short-and-ground” #1 was actually placed on downdropper of breaker 169/8-130 and “short-and-ground” #2 was placed on circuit breaker 169/8-430 isolating switch 169/8-439 instead of 169/8-437. These discrepancies were considered material to the cause of the outage, especially for “short-and –ground” (#1) which was placed at a different location from that agreed by the maintenance crew without the necessary updating of the PTW system for accountability.

The placement of the five (5) “short-and-grounds” by the JPS maintenance personnel is demonstrated in Figure 4.1 below.

Figure 4.1: Work Area at PAJ Substation with location of "short-and-grounds"



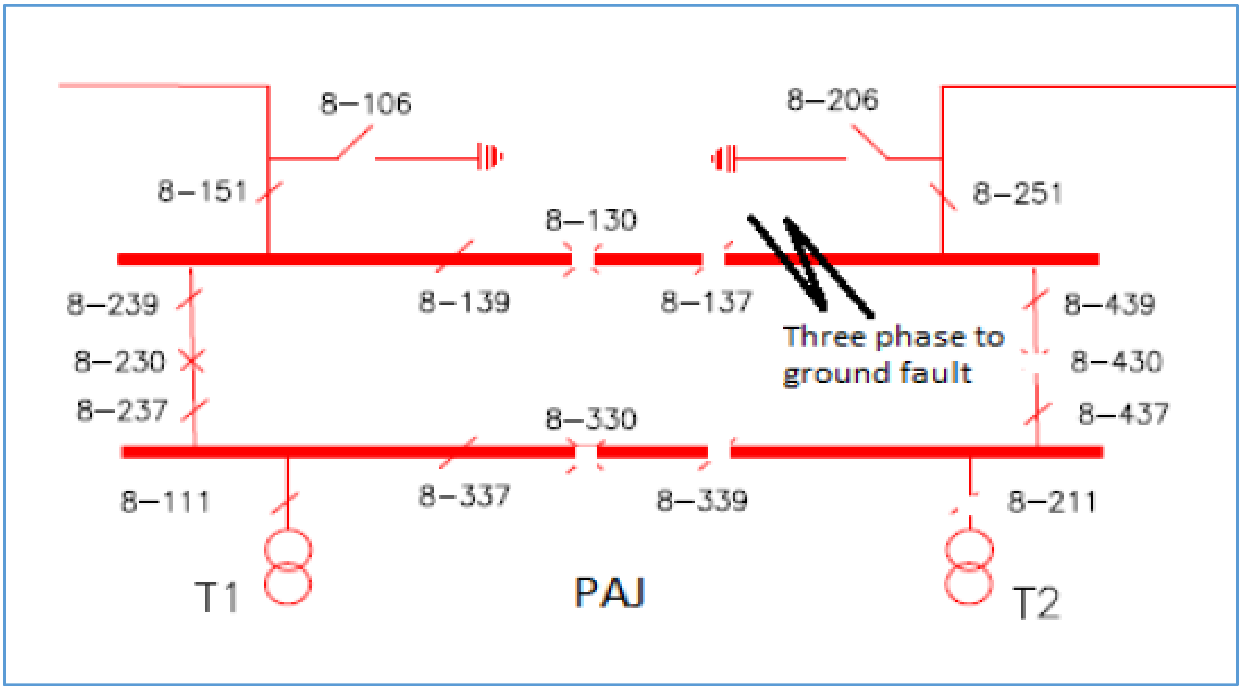
Source: JPS Supplementary Information to the JPS Major System Incident Technical Report - dated 2016 September 28

JPS' safety and switching procedures as well as prudent utility practice would dictate that the five "short-and-grounds" installed should be fully removed following completion of the maintenance and the cancellation of the LOTO PTW.

JPS reported that the maintenance works were completed at approximately 5:40 pm at which time the PTW was cancelled.

At 5:45 pm clearance was given to the System Controller by the field supervisor to re-energize the Hunts Bay – PAJ 69 kV line and return the System to normal operation. At the instant of re-energizing the line, the System experienced a solid three phase–to-ground fault, which was found to be caused by the fact that "short-and-ground" (#1), one of the five "short-and-grounds" installed as a safety measure to facilitate the maintenance work at the PAJ substation, was left in place in the vicinity of breaker 169/8-130. An illustration of the three phase-to-ground fault is shown in Figure 4.2 below.

Figure 4.2: Illustration of the Fault at the PAJ Substation



Source: JPS Transient Stability Study – dated 2016 October 31

4.1 Initiating Cause of the Outage

Based on the evidence provided, it was found that the initiation of the 2016 August 27 power blackout was caused by the failure of JPS' maintenance personnel to remove a "short-and-ground" (#1) left in place on the 69 kV transmission system in the vicinity of breaker 169/8-130 at PAJ that resulted in a solid three phase –to –ground fault on the System, upon re-energization of the Hunts Bay – PAJ 69 kV transmission line.

The described omission suggest that there are deficiencies in specific utility practices and human awareness that need to be addressed by the System Operator so as to provide assurance that it is capable of operating the Power System in a safe and reliable manner as required by the Licence and other relevant regulatory requirements.

5 EVALUATION OF THE SYSTEM SHUTDOWN INCIDENT

This chapter describes how the problems on the System evolved to a point that a cascading blackout and total System collapse became inevitable. The Review Team also sought to understand how and why the System collapse happened. The details of the SOE in the cascade are set out below, including specific details on how it was able to spread throughout the System uncontained.

5.1 Fault Clearance and Protection System Performance

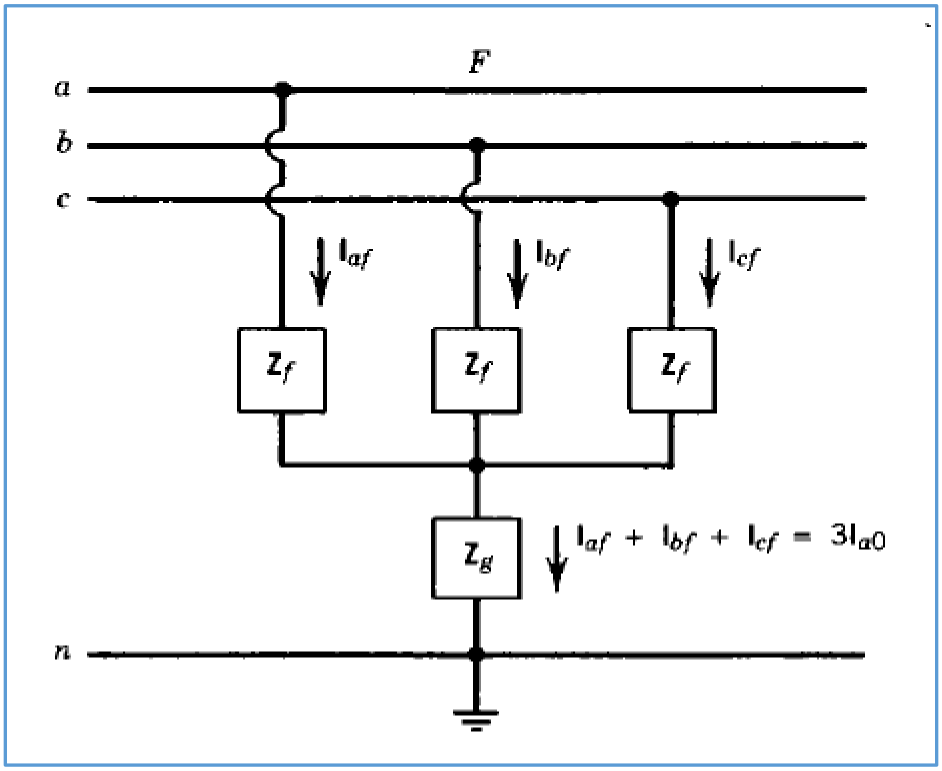
Major power blackouts are not usually normal occurrences, and each blackout scenario tends to feature different causation factors and conditions. The initiating events can be attributed to, among other things, human actions or inactions, load/generation imbalances, voltage problems, and protective relays mal-operation in response to short circuit faults.

A number of large-scale power blackouts start with short circuit faults on the transmission system. These fault conditions can result from natural causes such as the effect of lightning or wind on electricity conductor, inadequate vegetation management in right-of-way areas or improper actions as in the case of the 2016 August 27 System incident. A short-circuit fault usually causes a high current and low voltage on the electrical apparatus, such as a transmission line, on which the fault occurs. A protective relay for that transmission line is designed to detect the high current and low voltage and quickly trips the circuit breakers to isolate that line from the rest of the Power System.

A three phase-to-ground fault on transmission system occurs when the three phase conductors are connected through ground or when the three conductors contact the neutral of the three phase System.

A general representation of the three phase-to-ground fault is illustrated in Figure 5.1 below.

Figure 5.1: General Representation of a Three Phase-to-Ground Fault



5.1.1 Protection Relay Operation

It was found that for the three phase-to-ground fault incident on the 69 kV Transmission System at the PAJ substation, all the applicable protection schemes detected the fault condition and responded with varying degrees of outcomes as outlined below:

1. Enhanced Primary "A" high-speed Switch-Onto-Fault (SOTF) non-voltage dependent protection scheme with operating speed of within 100 ms detected the fault with the pick-up of its high-set overcurrent element. However, as reported by JPS, the relevant circuit breaker change of state never occurred. This means that the SOTF protection scheme failed to trip the circuit breaker and clear the fault as was expected.

   According to JPS, a defective cable was responsible for the malfunction of the SOTF protection scheme resulting in the relay not operating within the required time. JPS reported that the defect was corrected and the scheme tested and recommissioned.

2. Back-up directional overcurrent low-set inverse time delay with simulated operating delay of approximately 580 ms and back-up definite time directional overcurrent voltage dependent protection with time delay of 250 ms (part of the same relay) sensed the fault and initiated trip timers.

   The relay experienced a pick-up/drop-off chatter in excess of 90 ms, which extended the trip time beyond the design 250 ms for the high-set overcurrent element and prevented the relay from issuing a trip before the operation of the primary “A” and “B” zone 2 distance protection relays designed to operate in 400 ms. JPS reported that the relay was tested and found to be defective and was replaced.

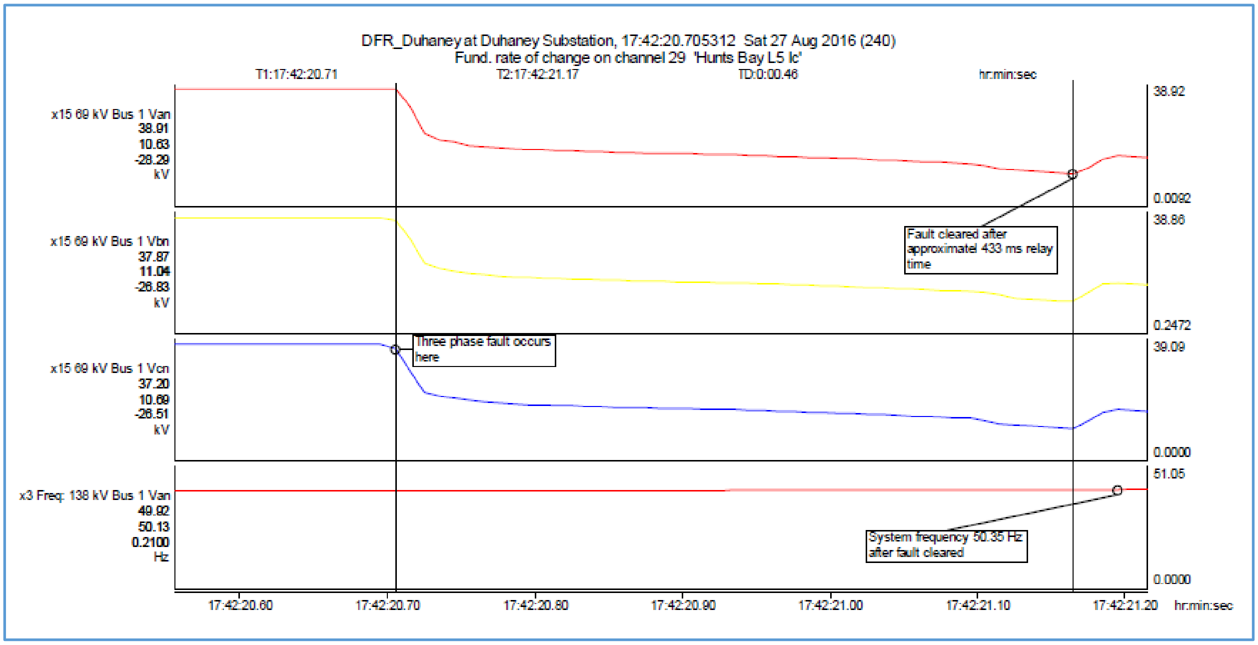
3. Primary “A” and “B” zone 2 distance protection operated as designed to clear the fault after a reported time 433 ms. This was evidenced by the Duhaney substation DFR disturbance records. (Refer to Figure 5.2 below).

A summary of the protection relays performance is shown in Table 5.1.

Table 5.1: Hunts Bay – PAJ 69 kV line Protection Relays Performance

Category	**Scheme**	**Design Time (ms)**	**Performance Status**	**Comments**
Primary	SOTF – incorporated primary “A” distance relay	100	Failed	Defective Control Cable
First line Back-up	Directional Overcurrent	250	Failed	Defective Relays
Second Back-up	Zone 2 Distance Protection	433	Operated	

Figure 5.2: JPS Duhaney DFR Disturbance Record Showing Fault Duration



Source: JPS Major System Incident Technical Report - dated 2016 September 28 (Section 5.2, page 17)

5.1.2 Circuit Breaker Operations

5.1.2.1 Circuit Breaker Operations to Normalize PAJ Substation

Table 5.2 describes the initial circuit breaker operations to facilitate normalization of PAJ substation following maintenance activities.

Table 5.2 Initial Circuit Beaker Operations to Normalize PAJ Substation

No.	Station	Breaker(s)	Status	SOE Time	Elapsed Time	Comments
(1)	Hunts Bay	Port Authority (8-250)	Open	17:40:15.691	00:00:00.000	Breaker opened by System Control
(2)	Hunts Bay	Port Authority (8-330)	Open	17:40:21.243	00:00:05.552	Breaker opened by System Control
(3)	Port Authority	Hunts Bay (8-251)	Close	17:42:45.342	00:00:29.651	Switch closed by System Control

Source: JPS Major System Incident Technical Report- dated 2016 September 28 (Section 3.2.2, page 9)

5.1.2.2 Circuit Breaker Operations after 265/8-250 was Test-closed

Table 5.3 outlines the SOE for other circuit breakers immediately following test closing of circuit breaker (265/8-250) at Hunts Bay substation.

Table: 5.3: Events after Circuit Breaker (265/8-250) at Hunts Bay Test Closed

Station	Circuit Breaker	Status	SOE Time	Elapsed Time	Comments
Hunts Bay	PAJ (169/8-250)	CLOSE	17:45:14.306	00:00.000	Breaker closed by System Control
JPPC	T1 HV CB 8-190	OPEN	17:45:14.713	00:00.407	27, Under-voltage
Hunts Bay	PAJ (169/8-250)	CLOSE	17:45:14.849	00:00.543	Distance relay – Z2-ABC, 4.05 miles. Fault cleared

Source: JPS Major System Incident Technical Report - dated 2016 September 28 (Section 3.2.2, page 10)

As shown in Table 5.3, JPS SOE records suggest a fault clearing time of 543 ms.

5.2 Fault Clearing Time

Regarding the clearing of the fault by primary “A” and “B” zone 2 distance protection, JPS under section 5 of the “Technical Report” JPS indicated the following:

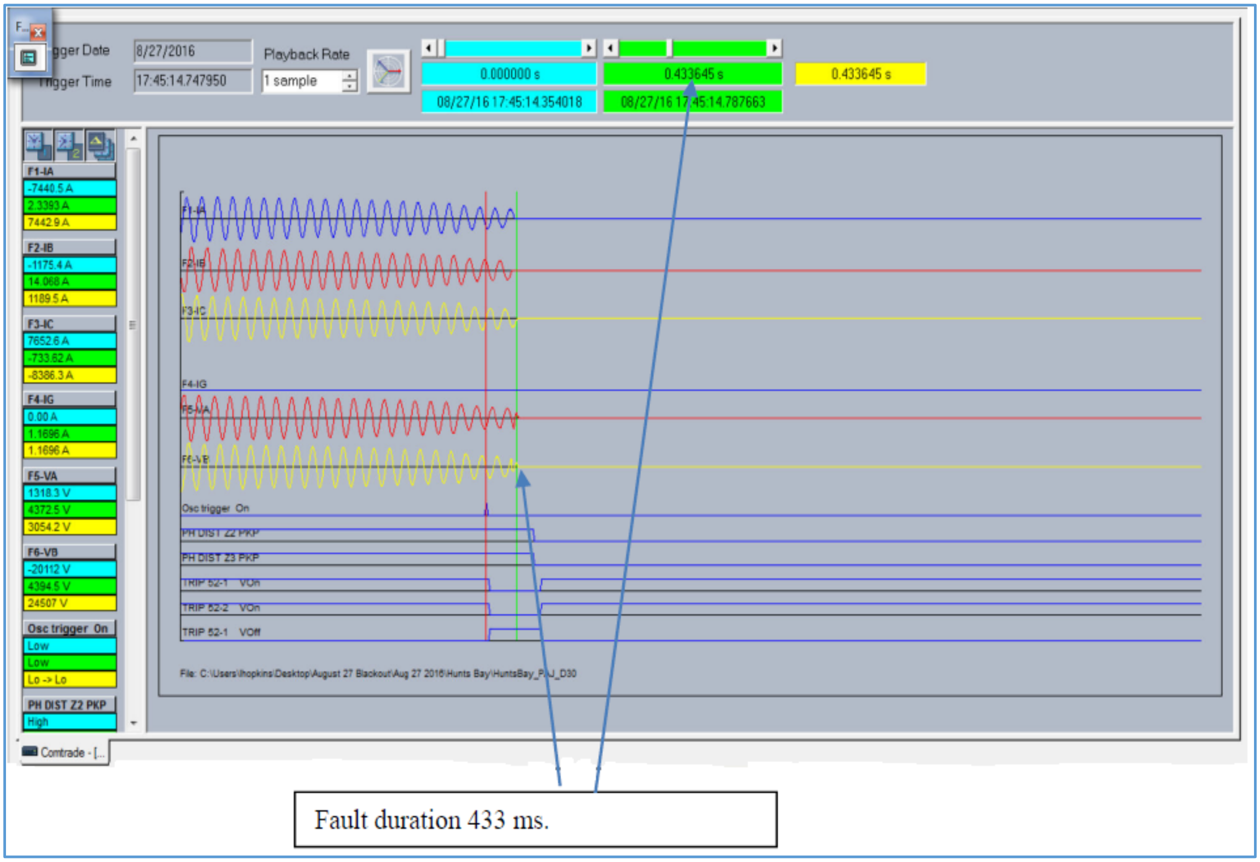
- Hunts Bay – PAJ Primary “A” zone 2 distance protection derived cumulative time of 413 ms with an extra 70 ms circuit breaker operating time.

- Hunts Bay – PAJ Primary “B” zone 2 distance protection operated in time delay of 400 ms with total fault clearing time of 433 ms.

The oscillography shown in Figure 5.3, was used by JPS to support this response of the primary “B” zone 2 distance protection. The information provided indicated that the fault inception time was [17:45:14.354018] and fault occurred at occurred [17:45:14.787663], translating to a fault duration of 0.433645 seconds (433 ms).

According to JPS, the time difference anomaly with the fault clearing time of 433 ms derived from the primary “B” trace shown in Figure 5.3 below is due to the fact that the primary “A” relay recorded two traces for the event with separate time stamps. JPS stated that when the time difference was calculated and the additional 3.5 cycles (70 ms) added, the cumulative time was 483 ms. On that basis, JPS affirmed that the fault clearing time of 433 ms as indicated by the DFR and primary “B” relay will be considered the official fault clearing time.

Figure 5.3: Hunts Bay-PAJ Primary "B" Zone 2 Distance Protection Fault Inception and Clearance



Source: JPS Major System Incident Technical Report - dated 2016 September 28 (Section 5.2, page 21)

JPS' declaration of the official fault clearing time appeared to have been partly substantiated by its Duhaney DFR disturbance records of the incident (section 5.2 of the "Technical Report"), particularly, the DFR response and line protection responses at Hunts Bay (PAJ line) including the plot (graph) shown in Figure 5.2 above. However, the information provided, does not clearly show how the fault duration was derived from those records.

Additionally, there were indications of disparities with the time references given for the SOE records, DFR records (eg. fault inception time – [17:42:20.70]) and those shown in the oscillography generated by the Hunts Bay – PAJ Primary "B" zone 2 distance protection. This brings into question the issue of time synchronization.

5.3 Cascade Phase of the Incident

5.3.1 System Cascade

A cascade occurs when there is a sequential tripping of numerous generating units and/or transmission lines in a particular area or subsystem of the Power System or the entire Power System. A cascade can be triggered by just a single initiating event, as was the case on 2016 August 27. Given the interconnected nature of the Power System, power swings, frequency variations, and voltage fluctuations caused by these initial events can cause other unaffected transmission lines to detect high currents and low voltages that appear to be faults, even when faults do not actually exist on those other lines. Generating units are tripped off-line during a cascade to protect them from severe power and voltage swings. Protective relaying systems are expected to function to protect transmission lines and generation plants from damage in the event of fault conditions and to ensure that the System can continue to operate under normal, steady state conditions. However, when the Power System operating limits are violated due to the effects of a severe fault which occurred on the System, it could lead to more and more lines and generators being tripped, thus widening the blackout area, with the eventual collapse of the System.

5.3.2 Cascading effect on August 27

According to the "Technical Report" after the fault was cleared in approximately 433 ms, the generating units online experienced varying degree of dynamic loading including power swings, which resulted in frequency and voltage excursions.

- A cascading effect ensued when JPPC unit 1 tripped on under-voltage and JPPC unit 2 tripped on under-frequency approximately 407 ms and 500 ms respectively after fault inception. All five (5) WKPP generating units tripped on over-speed within 500 ms after fault isolation followed by Rockfort units 1 & 2 on under-voltage and Hunts Bay unit B6 due to loss of excitation.

- All generating units online in the CA in close proximity to the fault suffered from this instability and tripped within 2.25 seconds after the fault was isolated with total generation loss of approximately 210 MW and 32 MVAr. These initial machine trips were followed by stage 0 operation of the automatic UFLS in an effort to effect the normal generation/load balance at nominal frequency.

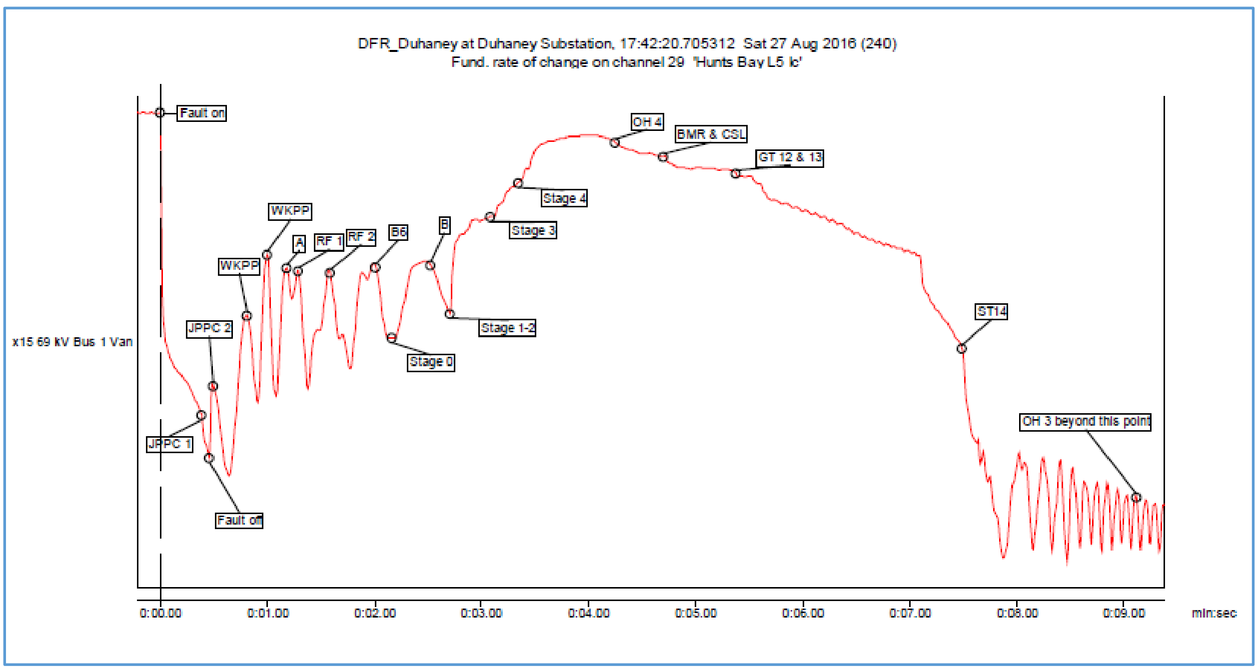
- All five (5) stages of the UFLS scheme operated but could not prevent the cascading effect of the outage as the remaining generators online in the Rural Areas were unable to maintain both active and reactive power demands of the System, as demonstrated by the declining values of frequency and voltage respectively. Accordingly, all generators including Old Harbour Unit 4, Bogue Combined Cycle Gas Turbine (CCGT) unit, JEP DG 9 & 11, Old Harbour Unit 3 and the hydro plants tripped on either under-voltage, under-frequency or overcurrent protection.

- The relevant DFR voltage trace lasted for approximately 9.5 seconds with extremely low voltage at the 9.5 seconds mark. The circuit breakers of the last major unit online, Old Harbour Unit 3, tripped 14.729 seconds after the fault was cleared.

Based on the time recordings, it was assumed that the total power blackout occurred approximately 15 seconds after fault inception.

The trip sequence of generating units on the System and voltage response is illustrated in Figure 5.4.

Figure 5.4: Duhaney DFR Disturbance Voltage Record with Generating Units Trips



Source: JPS Major System Incident Technical Report - dated 2016 September 28 (Section 5.3, page 22)

5.4 System Shutdown Sequence

The SOE including the tripping of the electrical plant and apparatus during the incident is set out in the following sections.

5.4.1 Generating Units Trip Sequence

The failure of the protection system to promptly clear the fault at the PAJ substation caused generating units on-line in the CA to experience severe instability due to over/under-speed, over/under-frequency and over/under-voltage.

The tripping sequence of generating units across the System were as follows:

1) JPPC units at Rockfort
2) WKPP units (#1, #2, #3, #4 and #5)
3) JPS SSD units at Rockfort (RF1 and RF2)
4) Hunts Bay Unit B6
5) Old Harbour Units #4
6) BMR Wind Generation Facility interconnect to the JPS Spur Tree Substation
7) Content Solar Generation Facility located at Content Village, Clarendon
8) Bogue CCGT
9) JEP Barge 2 (units #9 and #11)
10) Old Harbour Units #3
11) Other generators on the System

The tripping sequence of the generating units including the trip times, the elapsed time after fault clearance, and cause of the trips, is provided in Table 5.4. A detailed sequence of the shutdown event is provided in **Appendix 4** of this Investigation Report.

Table 5.4: Generating Units Trip Sequence

No.	Station	Breaker(s)	SOE Time	Elapse Time After Fault Cleared (ms)	Comments
1	JPPC	T2 HV CB 8-190	17:45:14.806[E]	43	27, Under-voltage
2	WKPP	#2 Gen CB 4-220	17:45:15.298	449	Over-speed
3	WKPP	#3 Gen CB 4-320	17:45:15.335	486	Over-speed
4	WKPP	#1 Gen CB 4-120	17:45:15.339	490	Over-speed
5	WKPP	#5 Gen CB 4-520	17:45:15.347	498	Over-speed
6	WKPP	#6 Gen CB 4-620	17:45:15.363	514	Over-speed
7	Rockfort	Unit 1	17:45:16[G&E]	1151	27B, 186G, Under-voltage
8	Rockfort	Unit 2	17:45:16[G&E]	1151	27B, 227L, 286G, 286T- Unde-rvoltage

9	Hunts Bay	Unit B6 CB 8-120	17:45:17.090	2241	40, 86G, 94T, 86SV
10	Hunts Bay	Unit B6 CB 8-650	17:45:17.103	2254	
11	Old Harbour	Unit 4 CB 9-420A	17:45:18.489	3640	Loss of Auxiliary power, 86G, 94T
12	Old Harbour	Unit 4 CB 9-420	17:45:18.489[E]	3640	
13	Spur Tree	BMR 8-630	17:45:18.927	4078	27, Under-voltage DTT Receive
14	Spur Tree	BMR 8-730	17:45:18.929	4080	27, Under-voltage DTT Receive
15	Content Solar	T1 CB 7-180	17:45:19.017	4168	81U-Under-frequency
16	Bogue	GT 13 CB	17:45:19.853	5004	81U-Under-frequency
17	Bogue	GT 12 CB	17:45:19.853[A]	5004	81U-Under-frequency
18	Bogue	ST14 CB 8-1490	17:45:21.830	6981	81U-Under-frequency
19	JEP	#9 Gen CB 4-620	17:45:21.386[GS]	7080	81U-Under-frequency
20	JEP	#11 Gen CB 4-420	17:45:21.386[GS]	7080	81U-Under-frequency
21	Rio Bueno	GSU CB 8-190	17:45:27.495	12646	81U-Under-frequency
22	Old Harbour	Unit 3 CB 9-320A	17:45:29.578	14729	Loss of Auxiliary power, 86G, 94T
23	Old Harbour	Unit 3 CB 9-320	17:45:29.595	14746	
Generation GPS synchronized Time [GS]			**Estimate [E]**	**Generator & Estimate [G&E]**	**Adjusted Time Based on plant SOE [A]**

Source Information: JPS Major System Incident Technical Report - dated 2016 September 28 (Section 3.3, page 11)

Based on the SOE records provided under section 3.2.2 of the “Technical Report”, the fault inception time was [17:45:14.306] and JPPC Unit#1 tripped on under-voltage 407 ms later and subsequently the fault was cleared at [17:45:14.849] resulting in a fault clearing time of 543 ms. (Refer to Table 5.3)

Based on the SOE record of the generating units trip times and the time elapsed relative to the fault isolation time, set out under section 3.3 of the “Technical Report”, JPPC Unit#2 trip time was estimated to be [17:45:14.806] with an elapsed time of 43 ms after fault clearance (Refer to Table 5.4). Given the time reference of [17:45:14.306] in Table 5.3, the SOE should have shown that JPPC Unit#2 tripped 43 ms before the fault was cleared.

Although the DFR disturbance voltage record exhibited in Figure 5.4 indicated that JPPC Unit#2 tripped after the fault was cleared, the basis on which JPS determined that JPPC Unit#2 tripped at [17:45:14.806] is unclear.

5.4.2 Trip Sequence of Transmission Lines and Other Equipment

JPS reported that the transmission line that tripped was the Hunts Bay – PAJ 69 kV line, which occurred at the inception of the fault.

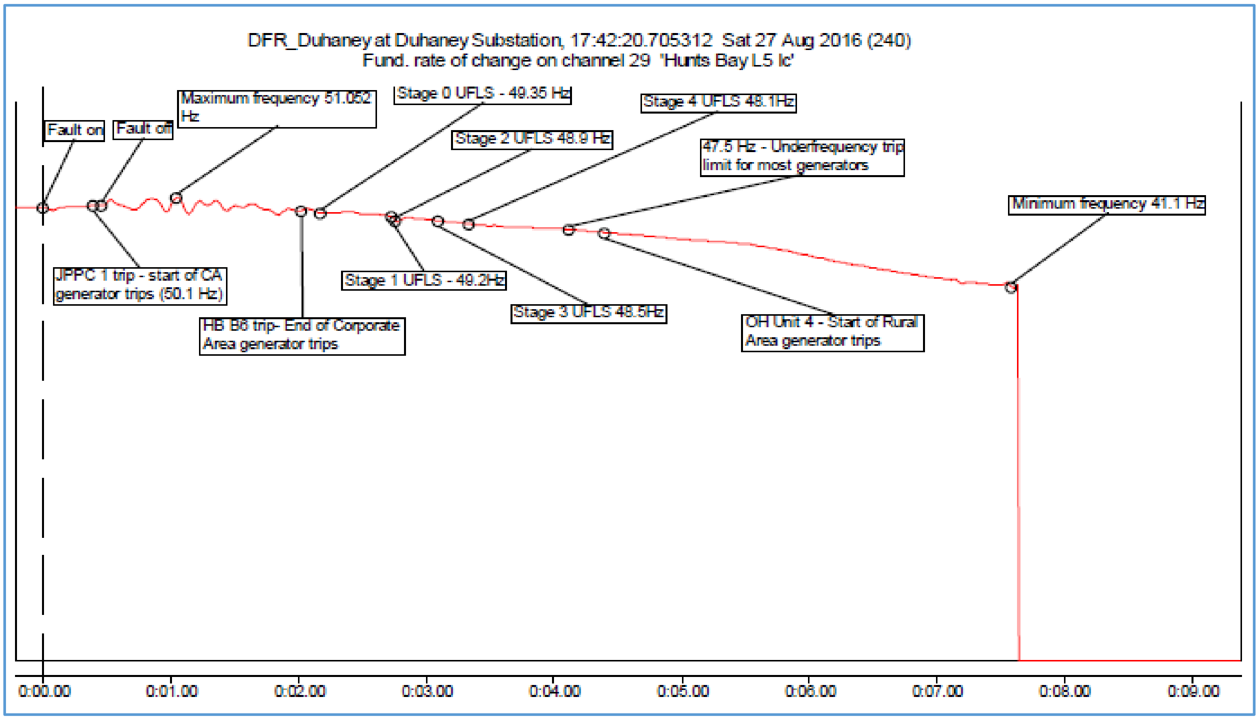
5.4.3 Under-frequency Load Shedding

Automatic UFLS relays located at various substations across the Power System are designed to trip distribution feeders and operated in an effort to save the System from collapse. These relays are currently set in (5) stages to shed blocks of load in sequence when the System frequency declines below the designated 50 Hz level.

Based on information provided in the "Technical Report", the System frequency remained close to nominal during the period of instability until all the generating units located in the CA tripped. Thereafter, System frequency declined triggering all five (5) stages of the automatic UFLS scheme as the remaining generators on-line begin to slow down.

The frequency response and operation of the automatic UFLS scheme is shown in Figure 5.5.

Figure 5.5: DFR Trace of Frequency Response and UFLS Relay Operation



Source: JPS Major System Incident Technical Report dated 2016 September 28 (Section 5.2, page 17)

Details of the operation of the automatic UFLS scheme during the incident is provided in **APPENDIX 2** of this Investigation Report**.**

5.4.3.1 UFLS Failure and Impact

The UFLS scheme is designed to protect the System from overloads and ensure continuous operation at reduced frequency within a prescribed range.

Accordingly, during the 2016 August 27 System incident, at the point when the generating units on-line started to trip, all five stages of the UFLS were required to operate to maintain balance between load and generation. However, problems were encountered with the UFLS operation at the JPS Hope substation. There was the failure of two (2) points in the UFLS at the substation to operate. This involved one (1) point in stage 2 and one (1) point in stage 3, which according to JPS was due to the loss of DC supply to the under-frequency relay as a result of a blown fuse.
JPS reported that the affected load shedding points were Liguanea Feeder 6-410 and Gordon Town Feeder 6-510 and the blown 125V DC fuses were replaced.

JPS also reported that the impact of such failures of the UFLS scheme would be the subject of further analyses and will be part of an Addendum report to its "Technical Report" submitted 2016 September 28. Information on these analyses was provided in subsequent documentation submitted to the OUR in relation to the subject outage.

5.4.4 SCADA and Communication System Availability during the Incident

Various components of the SCADA and remote control units located at generating stations and substations across the island were all required to function properly during the System shutdown incident.

It was indicated in the SCADA/EMS Report (Appendix E of the "Technical Report") that during the shutdown sequence, the SCADA/EMS system performed as expected. However, according to the ECS Report (Appendix F of the "Technical Report"), a number of substations were affected by loss of SCADA visibility after the System shutdown on 2016 August 27.

The substations/sites affected by loss of SCADA visibility and communication services on 2016 August 27 are shown in Table 5.5.

Table 5.5: Substations affected by Loss SCADA Visibility on 2016 August 27

Substations affected by Loss SCADA Visibility on 2016 August 27					
Substation Affected	**Time of Failure**	**Time to Restore**	**Description of Failure**	**Cause of Failure**	**Measures Taken**
Port Antonio	5:47 pm	8:26 pm	The site was operating on the backup SCADA link that was using Power Line Communication. This failed with the loss of power.	The PLC failed as a result of the line it traverses being out during the outage	SCADA visibility returned once power was restored. The burnt supply leg to the meter at Shotover was repaired which restored power to the site and the primary SCADA circuit
LWR	5:47 pm 8:56 pm	8:54 pm 9:40 pm	Loss of SCADA Visibility	The logs showed that the AC powered router on the inverter lost power during outage.	SCADA visibility returned once power was restored. Station power to the communication rack was removed to recreate the scenario of Aug 27, but the router did not lose power. As a failsafe the router was changed to a DC powered router on August 29.
Rockfort	5:46 pm	10:10 pm	Loss of SCADA visibility. All the communication equipment at the site was powered.	Garrettcom RS400 router lost the VLAN tunnel setup to pass SCADA traffic	A team was dispatched to the site on Aug 27 to power cycle the router which reestablished the communication to the site.
Goodyear	6:19 pm	7:43 pm	The SCADA link via Needham's Pen failed	An inverter at Needham's Pen failed resulting in a loss of power to the router.	The site was restored via an alternative link through Yallahs Hill.
Parnassus B	6:22 pm	7:13 pm	Loss of power to the communication rack.	One battery in the string was found to be defective due to a faulty battery contact. Quarterly battery test report shows last tested successfully on 2016 June 30.	SCADA visibility returned once power was restored. All four batteries and the battery contact cables were replaced on August 27
Hunts Bay	6:22 pm	7:13 pm	Loss of SCADA visibility. All the communication equipment at the site was powered.	Unknown and requires further investigation	A team was dispatched to the site on August 27. On arrival the communication to the site had already been restored.
Hope	7:13 pm 10:22 pm	9:23 pm 10:25 pm	Loss of power to the communication rack.	Batteries failed to provide full 8 hour back-up runtime. Quarterly battery test report showed they were load tested on 2016 May 31 and passed.	SCADA visibility returned once power was restored. All four Batteries were replaced on 2016 August 29.
Spur Tree A (Microwave Circuit)			Loss of SCADA visibility. All the communication equipment at the site was powered.	The IMUX Multiplexer was not passing the SCADA traffic	The IMUX shelf had to be physically power cycled on Aug 27 and SCADA visibility was restored.

Source: ECS Report (Appendix F of the JPS Major System Incident Technical Report - dated 2016 September 28)

6 RESTORATION OF SERVICE

6.1 Objective and Approach

The main objective of the restoration of service following a major System outage is to ensure that the electricity System is restored in a safe and stable manner and that electricity supply is also restored to customers in the shortest possible time; while minimizing adverse impact to the public and creating enough flexibility to alter the approach as the need arises.

Before re-energizing the System, it is important to undertake the following:

- Ensure that there are no existing hazards to personnel or property and/or plant and that all the relevant operations and management personnel are informed and their participating role appropriately defined

- Assess the availability generation resources and the elimination of the possibility of damage that may have occurred during the shutdown incident.

- Determine the status of circuit breakers and other critical switches,

- Identify available black-start capabilities

When it is established by the System Operator that restoration can proceed, the next step is to place in service those generating units that have “Black Start” capability. Subsequently reasonable attempts should be made to interconnect all the generating facilities via the transmission network and have as much generating units restarted and synchronized as soon as possible. Loadings on the generating units should be advanced to at least their minimum stable MW levels by restoring loads to the System, taking into consideration the load characteristics. The bulk power network will be strengthened while loads are restored.

When each respective energized sub-system is robust enough, customers should be gradually added as the available generation allows for maintaining the generation/load balance while being cognizant of unit loading levels, spinning reserve and System frequency.

6.2 System Restoration 2016 August 27

6.2.1 Restoration Time

Based on the “Technical Report”, the restoration of the System commenced at 6:11 pm after the status of the Power System and the readiness of Black Start units at Bogue and Hunts Bay including West Kingston were determined by the System Operator.

Customers started to regain supply within the first hour of restoration and within four hours, supply was returned to approximately 50% of customers, with 75% restored within five hours.

Total restoration of service to customers was completed at 11:22 pm on 2016 August 27 covering a time period of 5 hours and 37 minutes.

6.2.2 Restoration Challenges

The restoration exercise was carried out on a phased-basis but was slowed due to unexpected difficulties in bringing some of the generating units on-line, among other issues.

Some of issues encountered during the restoration process by the System Operator, include:

- Loss of SCADA communication to some power stations such as Rockfort and Hunts Bay resulted in employment of manual switching by field personnel.

- The land-line telephone system went down between 6:26 pm to 7:12 pm, which further impacted the restoration efforts.

- A defective synchroscope at Hunts Bay power plant, for breaker 265/8-230, resulted in a change of synchronizing strategy which impacted the restoration process.

- Problems encountered with GT10 on start-up.

7 TECHNICAL ANALYSIS

7.1 Analysis of System Shutdown Sequence

The System Shutdown on 2016 August 27 was analyzed in two phases:

1) Phase I - Voltage instability phase
2) Phase II - Frequency collapse phase

7.1.1 Voltage Instability Phase

This section describes the voltage collapse which occurred within the CA due to the low voltage condition that existed at the time of the fault.

The emergence of the three phase-to-ground fault resulted in depressed voltages throughout the System, consequently, generating units in the CA in close electrical proximity to the fault location experienced under-voltage and over/under-frequency triggering a System cascade.

The tripping of these generating units exacerbated the low voltage condition that existed within the CA sub-system and therefore delayed the voltage recovery process.

After WKPP units tripped off-line, the dynamic reactive power (MVAr) in the CA sub-system, which would normally provide voltage support was deprived. This impeded the recovery of busbar voltages to acceptable levels.

The extended low voltage condition within the CA sub-system resulted in the tripping of the JPS Rockfort generating units in approximately 1.151 seconds. By this time, a total of 152 MW of generation in the CA was lost, initiating the operation of the UFLS scheme in approximately 1.84 seconds, according to JPS SOE records.

The low voltage condition which prevailed on the System resulted in Hunts Bay unit B6 tripping off-line at 2.254 seconds after fault clearance, causing all 210 MW of generation in the CA to be disconnected.

Information provided in GEN-PLANTS Report (Appendix B of the “Technical Report”), indicated that all the WKPP generating units on-line experienced under-voltage at their respective generator busbars ranging from 5.39 kV – 6.11 kV just prior to all generator breakers opening.

WKPP reported that *"the megawatt over-ride alarm was activated on all the generating units indicating that the frequency limiter value of 52.50 Hz was exceeded"*. This would immediately send a trip signal to the generator circuit breakers. Frequency as high as 58.92 Hz was recorded on WKPP DG unit#6. It was not clear whether the megawatt over-ride alarm was activated automatically or through manual intervention.

Based on analysis, the low voltage condition that impacted the WKPP generating units, resulted in load rejection, because the units were not able to export all their active power generation to the System. The inability of the WKPP generating units to export electrical active power equivalent to the mechanical power input of the prime mover, resulted in uncontrolled over-speed and subsequent tripping of the units.

7.1.2 Frequency Collapse Phase

At the point when Hunts Bay unit B6 tripped off-line, a total of 210 MW of firm generating capacity was lost. This was in addition to approximately 21.6 MW of RE generation that was disconnected throughout the System during the same time period.

Table 7.1 gives the System overload for the first five (5) seconds of the initiating event, while Table 7.2 gives the System overload for the same time period, indicating that within that time period, a total of 290 .2 MW of generation was lost. Nevertheless, the System was already in a state of frequency collapse from the time Hunts Bay unit B6 tripped off-line.

Table 7.1: System Overload caused by Generating Units Tripping Offline

System Overload caused by Generating Units Tripping Off-line			
TIME	SYSTEM DEMAND	GENERATION LOST (MW)	% SYSTEM OVERLOAD
17:45:14	481.60	57.17	13.50 %
17:45:15	481.60	112.57	30.50 %
17:45:16	481.60	151.99	46.10 %
17:45:17	329.61	58.07	21.40 %
17:45:17	271.54	21.6	8.60 %
17:45:18	249.94	58.65	30.70 %

Table 7.2: Cumulative Generation Loss

Cumulative Generation Loss		
TIME	CUMULATIVE GENERATION LOSS (MW)	% SYSTEM OVERLOAD
17:45:14	57.17	11.9 %
17:45:15	112.57	23.4 %
17:45:16	151.99	31.6 %
17:45:17	210.06	43.6 %
17:45:17	231.56	48.1 %
17:45:18	290.21	60.3 %

7.2 Simulation Studies and Analysis

Power System simulations are used to predict and evaluate Power Systems performance under both steady state and fault conditions. These studies are usually comprised of load flow analysis, fault analysis and transient stability analysis. These studies are used to provide guidance to Power System operators and regulators in their decision making process.

7.2.1 Simulation Tool

The DIgSILENT Power System software package which is an internationally accepted simulation tool was used to carry out the analyses to better understand the behaviour of the System during the 2016 August 27 shutdown incident.

7.2.2 JPS Transmission Network Database

As per Item 31 of the OUR's "Information and Data Request from JPS for the August 27th, 2016 Power Blackout" a calibrated model of the Load Flow database that JPS intended to use in its transient stability analysis of the 2016 August 27 outage was requested. However, the format in which the model was submitted by JPS did not conform with the OUR's request.

Notably, the Transmission System database files that were provided could not be opened in DIgSILENT. After consultation with JPS, it was discovered that the problem was caused by software version related issues which prevented the PSS/E files from being imported into The DigSILENT software mode.

Those issues were eventually rectified, however, there were additional problems encountered after the files were accessed. These include:

a) The total input load data that was provided by JPS adds up to 434.4 MW and the system demand was 481.6 MW prior to the system collapse;
b) Caribbean Cement Company Limited, Duncans and PAJ were not included in the dataset;
c) Errors within the SCADA data provided, for which no explanations given; and
d) The comparison between the online and offline Load Flow programme were not provided.

Taking these constraints into account, the Load Flow database submitted was modified, using data provided for the steady state analysis, along with other relevant data previously provided by JPS.

7.2.3 Simulation of System Performance

In order to analyze the performance of the Power System during the 2016 August 27 shutdown incident, and to examine the ability of the System to withstand certain contingencies, a number of simulation studies using scenario analysis were conducted.

7.2.3.1 Steady State Load Flow Analyses

The following cases were carried out for both the day peak of 481.68 MW. It should be noted that the network was already in the N – 1 line outage contingency state, because of work that was being carried out at sections of the PAJ substation. For this outage, the Hunts Bay – PAJ 69 kV line was taken out of service and the live section of the substation was fed from the PAJ – Duhaney 69 kV line.

The voltages at critical substations are given in Table 7.3.

Table 7.3: Voltage at Critical Substation Busbars

Substation Busbar	Rated Voltage (kV)	JPS SCADA		OUR Simulation	
		kV	pu	kV	pu
Bogue	138	136.1	0.9862	138.8	1.006
Duhaney	138	135.7	0.9830	140.1	1.015
	69	70.8	1.0262	72.3	1.048
Old Harbour	138	137.4	0.9958	143.1	1.037
Tredegar	138	139.8	1.0129	140.5	1.018
	69	69.5	1.0067	71.3	1.033
PAJ	69	0.5	0.0074	72.2	1.047
Hope	69	70.6	1.0235	71.7	1.040
Hunts Bay	69	70.9	1.0277	72.7	1.054
Rockfort	69	72.0	1.0442	72.6	1.052

The loadings on critical transmission line are given in Table 7.4. below.

Table 7.4: Loading on Critical Transmission Lines

		JPS SCADA					OUR Simulation	
Base Case Load Flow with Hunts Bay – PAJ 69 kV lines Out	Loadings on Critical Lines	MW	MVar	MVA	Amps	Loading (%)	Amps	Loading (%)
	Hunts Bay – Three Miles 69 kV	42.762	9.262	43.753	182.9	35.5	344.6	66.9
	Three Miles – Washington Blvd 69 kV	31.049	6.121	31.647	132.3	25.7	265.7	51.6
	Hunts Bay - Duhaney 69 kV			0.000	0.0	0.0	333.7	64.8
	Rockfort - Up Park Camp 69 kV	39.712	4.039	39.917	166.9	25.7	220.4	42.8
	Duhaney - PAJ 69 kV	3.495	-2.129	4.092	17.1	3.3	23.7	4.6
	Hunts Bay – Greenwich Rd 69 kV	7.895	6.818	10.431	43.6	8.5	53.6	10.4
	Duhaney - Washington Blvd 69 kV	-12.780	8.367	15.275	63.9	9.8	133.9	20.6

7.2.3.2 Stability Study

Electromechanical transient stability study is a time domain representation of the electric Power System and is used to determine the ability of the Power System to remain stable after being subjected to major Power System disturbances. For the 2016 August 27 incident, total System blackout occurred within fifteen (15) seconds following the initiating event. However, the ability of the System to remain stable would have been determined long before that time period, and the instability of the System if it occurs can be evaluated among any of the three major categories of stability, viz:

1) Rotor angle stability
2) Voltage stability and
3) Frequency stability

In light of the above, a stability study was carried out to determine the point at which the System became unstable, which precipitated the complete shutdown of the System on 2016 August 27.

The scenarios that were examined and analyzed are set out in section 7.2.3.3.

7.2.3.3 Stability Case Description

Case #1: Recreation of the System conditions that lead to the JPS Power System blackout of 2016 August 27.

Case #2: Solid three phase-to-ground fault at PAJ substation, cleared by primary "A" SOTF scheme in 100 ms (5 cycles).

Case #3: Solid three phase-to-ground fault at PAJ substation, cleared first line back-up protection at Hunts Bay substation in 250 ms (12.5 cycles).

Case #4: Solid three phase-to-ground fault at PAJ substation, cleared second line backup protection at Hunts Bay substation in 433 ms (21.7 cycles).

Case #5: Solid three phase-to-ground fault at PAJ substation, cleared second line backup protection at Hunts bay 433 ms (21.7 cycles) with UFLS points that failed during the blackout not included and JPPC units #1 and #2 tripped in 407 ms and 455 ms respectively.

Case #6: Solid three phase-to-ground fault at PAJ substation, cleared second line backup protection at Hunts bay in 433 ms (21.7 cycles) with UFLS points that failed during the blackout not included and JPPC units #1, and WKPP units tripping according to SCADA report.

Case #7: Solid three phase-to-ground fault at PAJ substation, cleared second line backup protection at Hunts Bay 433 ms (21.7 cycles) with UFLS points that failed during the blackout and JPS Rockfort generating units tripping offline according to SCADA.

Case #8: JPPC units #1 and #2 tripped offline, All UFLS points included.

Case #9: JPPC units #1 and #2 and WKPP units tripped offline, All UFLS points included.

Case #10: JPPC units #1 and #2, WKPP units, Hunts Bay unit B6, tripped offline, All UFLS points included.

Case #11: JPPC units 1 and 2 WKPP, Hunts Bay unit B6 and RF1 units tripped off-line, All UFLS points included.

Case #12: Determination of CFCT under the existing network configuration, at: (a) Hunts Bay substation, (b) Rockfort substation, (c) Duhaney substation, and (d) PAJ substation.

Case #13: Determination of CFCT with the transmission system intact, at: (a) Hunts Bay substation, (b) Rockfort substation, (c) Duhaney substation, and (d) PAJ substation.

7.3 Simulation Results

Table 7.5 gives the ranges to which selected generator terminal and bus voltages vary during the application and removal of the fault conditions for Cases #1 to #7 and Table 7.6 below gives the frequency ranges for all thirteen cases.

The voltage and frequency plots for Case #1 are given in Figures 7.1 to 7.8 below. The voltage and frequency plots for Cases #2 to #11 are provided in **APPENDIX 3** of this Investigation Report.

Table 7.5: Generator and Bus Voltage Variations

Case #	**Station**	**Voltage Profile**								
		Generator					**69 kV Bus**			
			Minimum		Final		Minimum		Final	
		unit	pu	Time(s)	pu	Time(s)	pu	Time (s)	pu	Time(s)
1	Hunts Bay	B6	0.313	0.433	0.803	0.894	0.195	0.433	0.803	0.782
		WKPP	0.198	0.433	0.801	0.752				
	Rockfort	RF1	0.436	0.433	0.801	0.626	0.243	0.429	0.794	0.762
		JPPC 1	0.42	0.407	Unit tripped					
2	Hunts Bay	B6	0.556	0.1	0.802	0.103	0.335	0.1	0.802	0.104
		WKPP	0.444	0.1	0.802	0.103				
	Rockfort	RF1	0.551	0.1	0.802	0.103	0.397	0.1	0.803	0.104
		JPPC 1	0.503	0.1	0.802	0.103				
3	Hunts Bay	B6	0.463	0.25	0.801	0.269	0.3	0.25	0.803	0.255
		WKPP	0.351	0.25	0.805	0.272				
	Rockfort	RF1	0.511	0.25	0.801	0.256	0.362	0.25	0.803	0.255
		JPPC 1	475	0.25	0.801	0.254				
4	Hunts Bay	B6	0.326	0.432	0.792	0.635	0.218	0.432	0.811	0.575
		WKPP	216	0.432	0.791	0.585				
	Rockfort	RF1	0.459	0.432	0.794	0.535	0.28	0.432	0.795	0.565
		JPPC 1	0.408	0.432	0.79	0.565				
5	Hunts Bay	B6	0.313	0.433	0.814	0.737	0.198	0.429	0.796	0.647
		WKPP	0.198	0.433	0.797	0.647				
	Rockfort	RF1	0.429	0.438	0.801	0.597	0.24	0.433	0.803	0.647
		JPPC 1	0.436	0.407	Unit tripped					

6	Hunts Bay	B6	0.313	0.433	0.801	0.887	0.195	0.433	0.803	0.782
		WKPP	0.198	0.433	0.797	0.742				
	Rockfort	RF1	0.43	0.433	0.8	0.632	0.24	0.433	0.805	0.772
		JPPC 1	0.42	0.407	Unit tripped					
7	Hunts Bay	B6	0.313	0.433	0.801	0.887	0.195	0.433	0.803	0.782
		WKPP								
	Rockfort	RF1	0.429	0.438	0.8	0.632	0.24	0.433	0.794	0.762
		JPPC 1	0.42	0.407	Unit tripped					

The System frequency profile obtained from the simulations is provided in Table 7.6.

Table 7.6: System Frequency Profile

Case #	System Frequency			
	Minimum		Final	
	Hz	Time (s)	Hz	Time(s)
1	42.497	10	42.497	10
2	49.968	1.992	49.995	10
3	49.929	2.082	49.995	10
4	49.881	3.115	49.994	10
5	48.827	2.634	50.215	10
6	48.223	2.185	50.394	10
7	48.02	2.171	50.498	10
8	48.848	1.914	50.2	10
9	48.325	1.753	50.412	10
10	47.881	2.844	48.648	10
11	45.798	10	45.798	10

The CFCTs at selected 69 kV substation busbars are given in Table 7.7.

Table 7.7: Critical Fault Clearing Time (CFCT)

Case #		Fault on Line 5% from Busbar	Bus Name		CFCT (Cycle)	
			Name	Voltage (kV)	JPS	OUR
12	a	Hunts Bay – PAJ line, 5%	PAJ	69	N/A	23
	b	Hunts Bay – PAJ line, 5%	Hunts Bay	69	11	10.5
	c	Hunts Bay – Duhaney line, 5%	Duhaney	69	13	14.5
	d	Rockfort – Up Park Camp line, 5%	Rockfort	69	10	11.5
13	a	Hunts Bay – PAJ line, 5%	PAJ	69	N/A	11
	b	Hunts Bay – PAJ line, 5%	Hunts Bay	69	11	15.5
	c	Hunts Bay – Duhaney line, 5%	Duhaney	69	13	14
	d	Rockfort – Up Park Camp line, 5%		69	10	12

Figure 7.1: Case #1 - Generator Terminal Voltage (Bogue, OH, JPPC, RF)

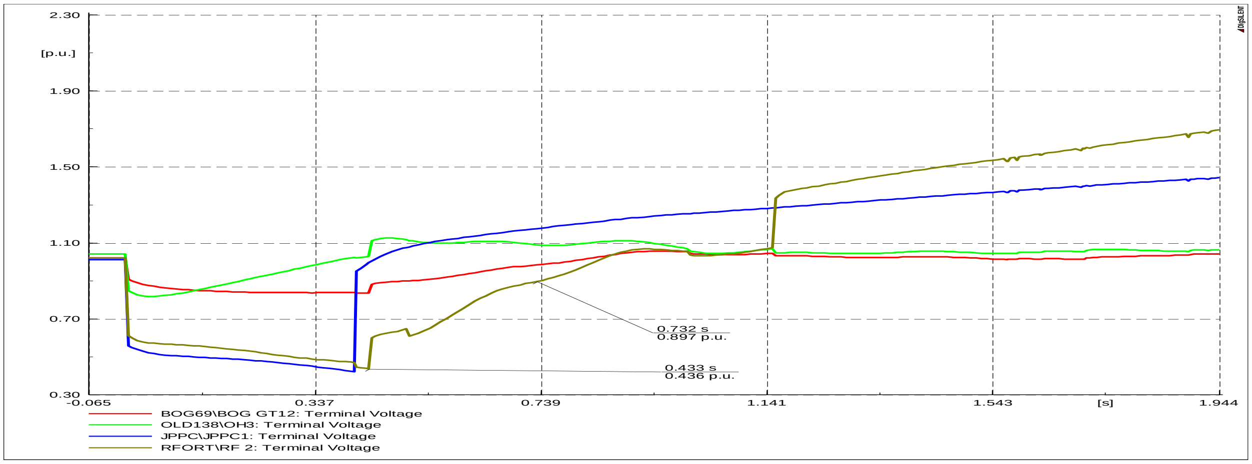


Figure 7.2: Case #1 – Generator Terminal Voltage (Bogue, OH, HB, RF)

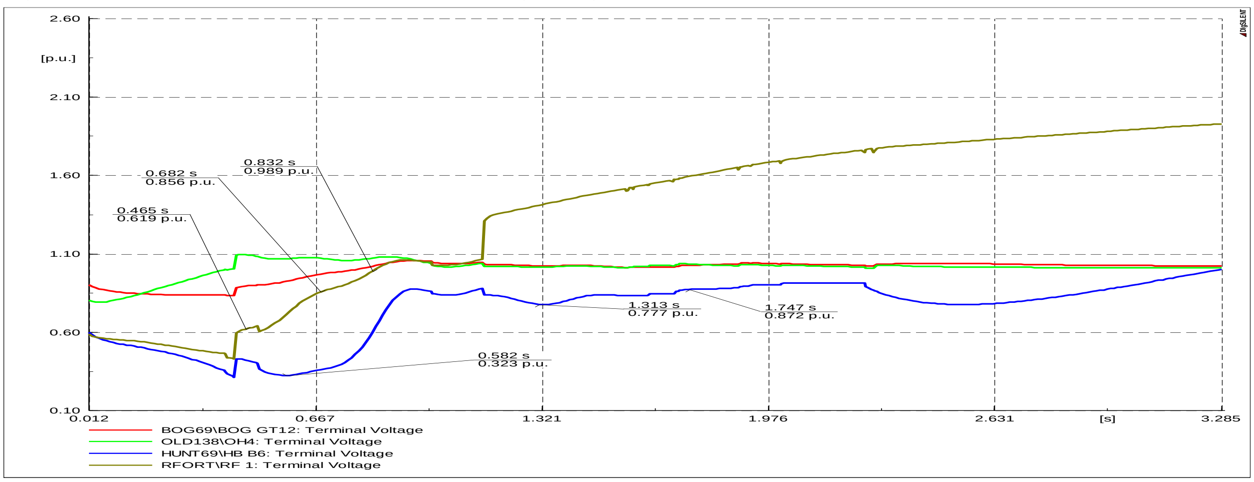


Figure 7.3: Case #1 - Generator Terminal Voltage (Bogue, JEP, JPPC, WKPP)

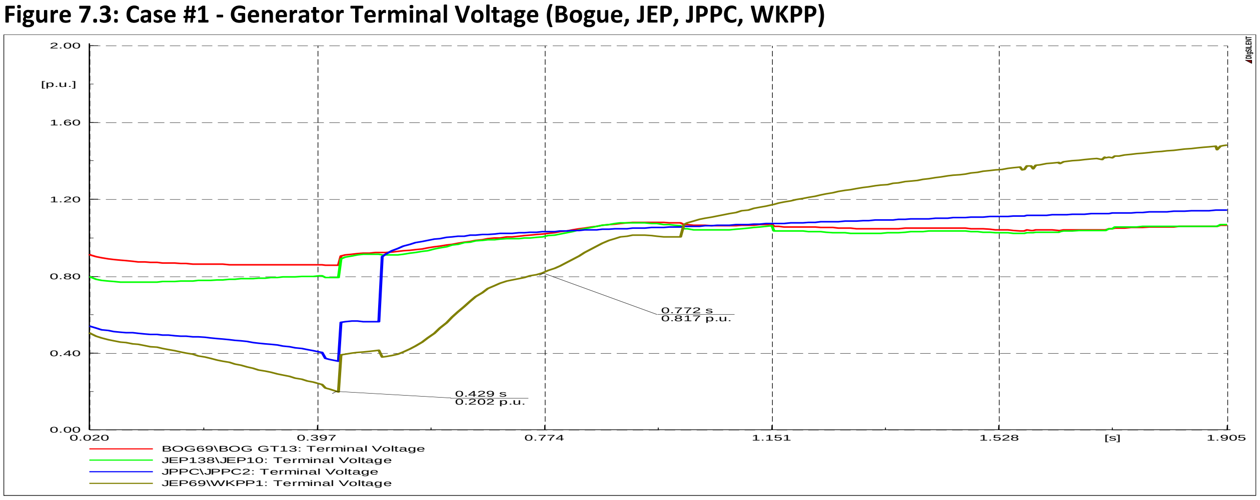


Figure 7.4: Case #1 – Substation Busbar Voltage (RF, Paradise, Tredegar, Cardiff Hall)

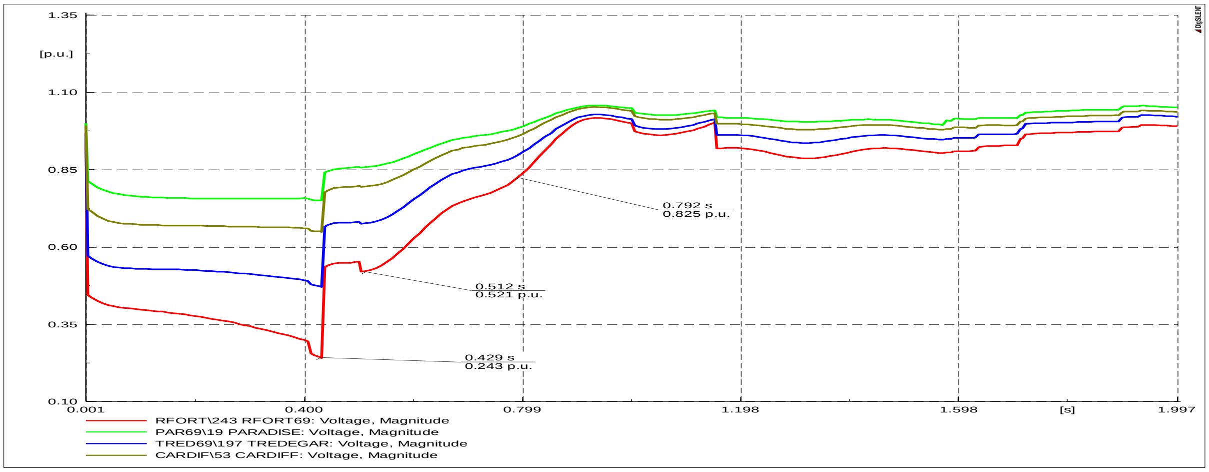


Figure 7.5: Case #1 – Substation Busbar Voltage (HB, Bogue, OH, Spur Tree)

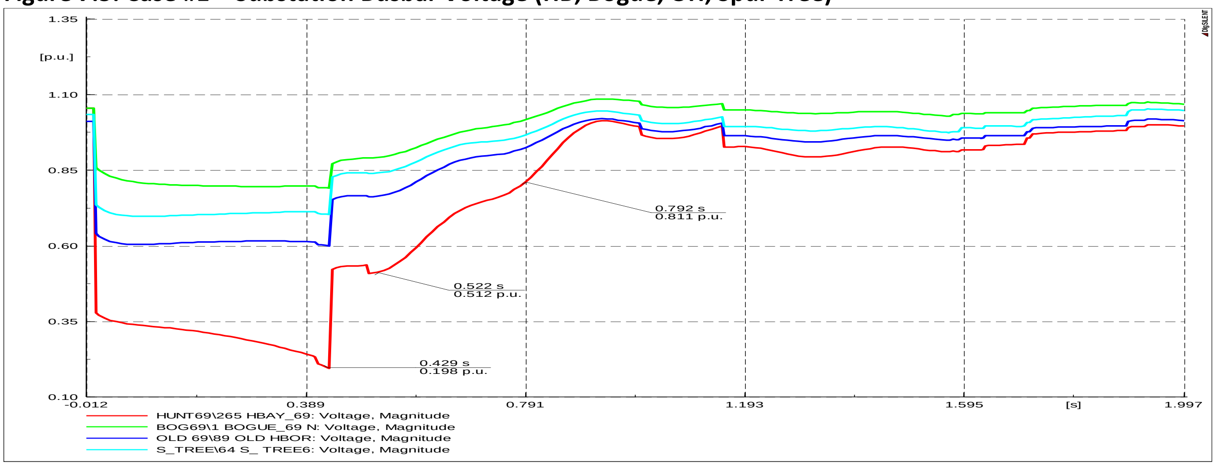


Figure 7.6: Case #1 – Substation Busbar Voltage (Duhaney, Lyssons, Paradise, Ohio Rios)

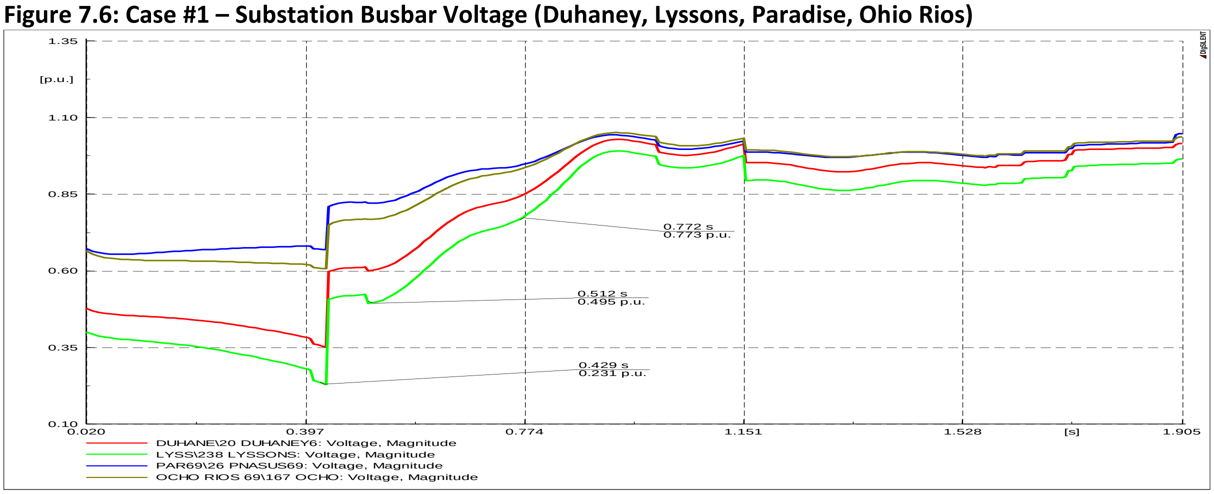


Figure 7.7: Case #1 – Substation Busbar Voltage (Hope, Maggotty, Micheton Halt, Port Antonio)

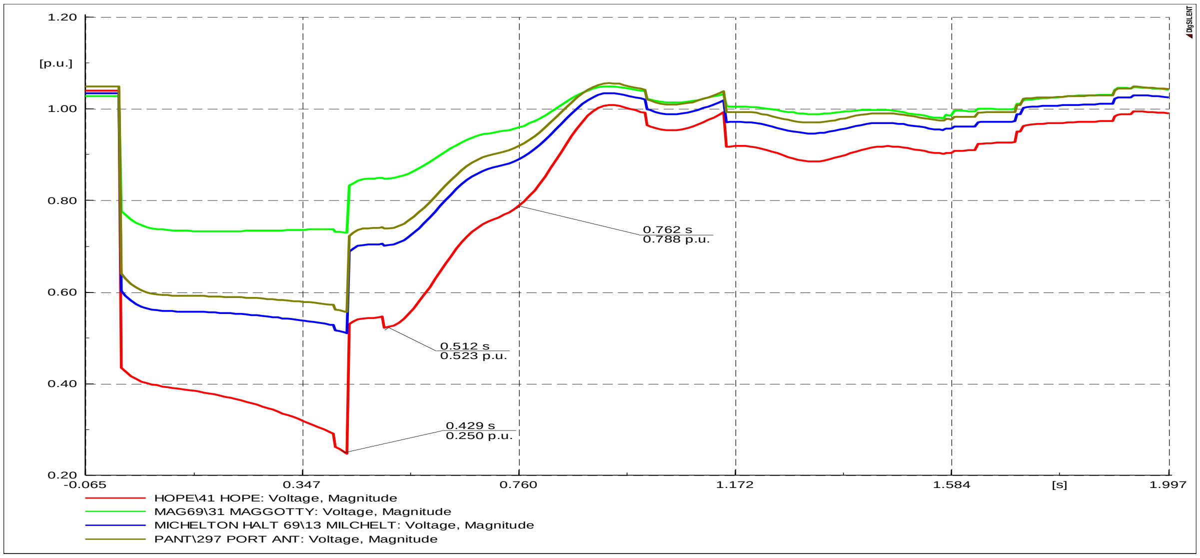
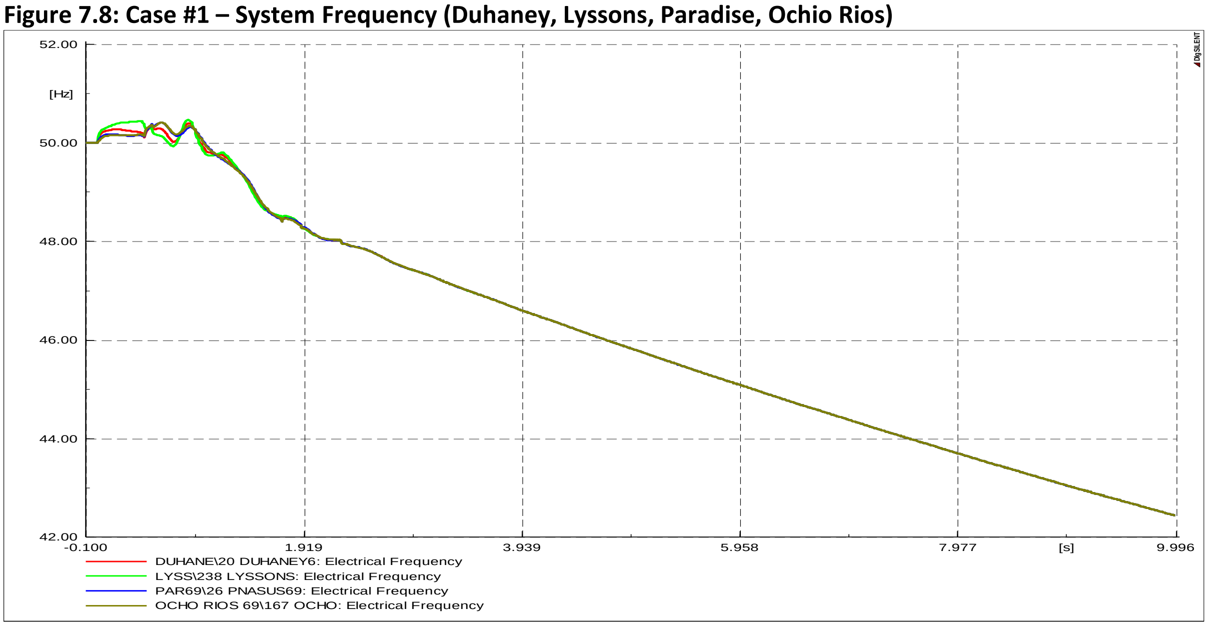


Figure 7.8: Case #1 – System Frequency (Duhaney, Lyssons, Paradise, Ochio Rios)



7.4 Discussion

7.4.1 Load Flow Analysis

With the Hunts Bay – PAJ 69 kV line out of service, the Power System was already in the N – 1 line outage contingency mode.

Busbar voltages at Hunts Bay and Rockfort were the highest, reaching 105.4% and 105.2% of their nominal values respectively. However, they were within the +10% voltage contingency limit. The most heavily loaded CA 69 kV transmission lines were the Hunts Bay - Three Miles line and Three Miles – Washington Boulevard 69 kV lines which were 53% and 51.6% loaded respectively. All other CA transmission circuits were loaded below 50% of their thermal rating. It can therefore be concluded that although the network was operating in the N – 1 line outage contingency mode, it was in good operating condition. Just prior to the System failure about 21 MW of generation was exported from the CA sub-system.

7.4.2 System Stability

Case #1 of the evaluation scenarios was executed to recreate the cascading events that lead to the power blackout. The simulation results show a wide voltage variation across generator terminals, with the lowest of 19.8% of nominal value occurring at the WKPP Complex. At this location it took about 544 ms for the terminal voltages to rise to about 80% of its nominal value.

This slow voltage recovery time was due to the tripping of both JPPC units #1 and #2 off-line. This deprived the System of needed dynamic reactive power (MVAr) support. At the time when JPPC unit #1 tripped, its terminal voltages were about 42% of its nominal value.

Figures 7.1 to 7.8 above give the terminal voltages for selected generators and also bus voltages and frequencies at selected locations throughout the System.

In Case #2, the fault cleared in 100 ms and all generator terminal voltages reached 80% of nominal voltage in 103 ms and the System quickly settled down to a new and stable operating state, as are shown in Figures 7.9 to 7.15 in **APPENDIX 3** of this Investigation Report, and the frequency range were well within specified limits of 50 Hz +/-0.2 Hz.

For Case #3, the fault cleared in 250 ms, the voltage recovery process was not as uniform is in case #2. The voltage across the WKPP generating units' terminal voltages dipped to as low as 35.1% of nominal value and took 12 ms to reach 80% of their nominal value, as are shown in

Table 7.5 and Figures 7.16 to 7.22 in **APPENDIX 3** of this Investigation Report. The frequency throughout the System were still within specified limits of 50 Hz +/-0.2 Hz. The System again recovered to a new but stable operating state.

The clearing of the fault in Case #4 in 433 ms also caused the System returning to a stable operating state as shown in Figures 7.23 to 7.29 in **APPENDIX 3** of this Investigation Report with the System frequency remaining within the specified limits of 50 Hz +/- 0.2 Hz.

Cases #5, #6 and #7 tested the System's response for the clearance of the fault in 433 ms along with the tripping of generating units as described in the named cases, representing 13.5% (57.17 MW generation loss), 30.5% (112.6 MW generation loss) and 46.4% (152 MW generation loss) System overloads respectively. The corresponding low frequency point occurred at 48.827 Hz, 48.223 Hz and 48.02 Hz respectively after automatic UFLS operations. Their respective voltage and frequency plots are shown in Figures 7.30 to 7.51 in **APPENDIX 3** of this Investigation Report.

Cases #8, #9, #10 and #11 were used to evaluate the effectiveness of the existing automatic UFLS scheme by just tripping generation units off-line. The results showed that the System would be able to recover from a 54.7% System overload, which is equivalent to a 35.4% generation loss, provided that no other generating unit tripped off-line due to the low frequency condition of 47.881 Hz that the System experienced as shown in Figures 7.52 to 7.55 in **APPENDIX 3** of this Investigation Report.

Cases #12 and #13 were conducted to indicatively estimate the CFCT, based on the System configuration on 2016 August 27, within the constraints, limits and margin of error associated with the network model that was created.

The CFCT estimated from the simulation results are presented in Table 7.7.

Based on the calculations, the CFCT for a fault on the Hunts Bay – PAJ 69 kV line was estimated to be 23 cycles (460 ms). Within the limits of accuracy of the model, it can be deduced that the estimated CFCT and fault clearing time of 433 ms affirmed by JPS do not differ considerably.

Notably, the JPS System Stability Analysis did not definitively address the issue of CFCT in relation to the incident and therefore this requires further evaluation and analysis, subject to the construction of a fully representative network model.

8 THE 2016 AUGUST 27 SYSTEM SHUTDOWN COMPARED WITH PREVIOUS MAJOR POWER OUTAGES IN JAMAICA

8.1 Overview

Momentary and short duration service interruptions and localized outages occur on the electricity System very frequently. Conversely, System-wide disturbances that affect a significant portion of or the entire customer base across the Island are usually rare events. However, the records show that these outages have occurred on the Jamaican Power System more frequently than expected or predictions based on probabilistic assessment.

Over the past ten (10) years, electricity customers Island-wide, on seven (7) occasions including 2016 August 27, have experienced extended power outages resulting from a complete or partial shutdown of the JPS electricity System.

In each case, the power blackout was the result of a cascading failure of the Power System, in which seemingly small and localized problems caused the System to become unstable and subsequently affected a much wider area.

Preventing such blackouts is an important goal that requires a dedicated operational approach by the System Operator as well as the validation and monitoring of the state of the Power System at all times in accordance with the relevant legal and regulatory framework for the electricity.

These outages occurred on the following dates and for the reasons indicated in Table 8.1:

Table 8.1: Synopsis of Previous Major System Outages in Jamaica since 2006

Previous Major System Outages in Jamaica since 2006						
No.	**DATE OF OUTAGE**	**FAULT AREA/ APPRATUS**	**CAUSE OF OUTAGE**	**EXTENT OF OUTAGE**	**NUMBER OF CUSTOMERS AFFECTED**	**DURATION**
1	2006 July 15 (4:16 PM)	Duncans/ Bogue 138 kV Transmission Line	Failure of distance protection relays to operate at JPS Duncans substation to clear a fault following a lightning strike to the Duncans - Bogue 138kV transmission line.	Total Power Blackout	Approx. 563,000	511 Minutes
2	2007 July 3 (5:11 AM)	JPS Old Harbour Power Station	Failure to clear a fault on lightning arresters for Unit # 2 GSU transformer at JPS Old Harbour power station when one pole of the 138kV circuit breaker in the switchyard failed to open properly.	Total Power Blackout	Approx. 576,600	708 Minutes
3	2008 January 9 (6:12 PM)	Duhaney/ Tredegar 138 kV Transmission Line	Non-clearance of a fault on the Duhaney - Tredegar 138kV transmission line at the Tredegar substation after a wooden transmission support pole fell to the ground.	Total Power Blackout	Approx. 582,000	263 Minutes
4	2012 August 5 (11:59 PM)	Duhaney/ Naggo Head 69kV Transmission Line	Failure of the protection system to clear a fault at pole #1 on the Duhaney - Naggos Head 69kV transmission line.	Total Power Blackout	Approx. 588,014	567 Minutes
5	2013 March 30 (1:37:59 PM)	JPS Duhaney Substation	The rupture of a newly installed 69 kV Voltage Transformer (VT) during commissioning tests resulting in a fault on the System.	Partial Power Blackout (All Parishes Affected)	527,021	457 Minutes
6	2016 April 17 (6:59 PM)	Hunts Bay/Three Miles 69 KV Transmission Line	The trip of the Hunts Bay-Three Miles 69 KV Transmission Line on overcurrent (current limit exceeded), during the return of the System to normal operation following a planned outage.	Partial Power Blackout (All Parishes Affected)	547,734	230 Minutes
7	2016 August 27 (5:45 PM)	PAJ Substation	Failure of JPS maintenance personnel to remove a "short-and-ground" placed on the 69 kV transmission system in the vicinity of breaker 169/8-130 at PAJ substation, resulting in a solid three phase –to –ground fault on the System, precipitating a complete collapse of the System.	Total Power Blackout	Approx. 629,000	337 Minutes

8.2 Details of Previous Major System Outages

In the following sections, the seven (7) previous System outages identified in section 8.1 are discussed and compared with the power blackout of 2016 August 27.

8.2.1 The 2006 July 15 Total System Shutdown

This outage event resulted in the loss of 465.6 MW of load and caused the total customer base (approximately 563,000 customers) island-wide to experience disruption in their electricity supply for time periods of up to 8.5 hours.

8.2.1.1 Causal Factors - 2006 July 15 Total System Shutdown

The major causation factors associated with incident were as follows:

i) The System shutdown was initiated by a three-phase transient fault on the Duncans/Bogue 138 kV transmission line that was caused by a lightning strike at Tower #75.

ii) The primary protective relays at JPS' Duncans substation end of the Duncans/Bogue 138 kV transmission line failed to clear the fault as designed thereby initiating the system collapse.

iii) The back-up protection scheme at that said Duncans substation and those located remotely at Bellevue and Kendal substations also failed to operate and clear the fault.

iv) The failure of the primary, as well as, the backup protection to operate was due to the absence of a DC voltage supply because a 125V breaker had previously tripped taking both circuits out of service. Remote status alarms which would have alerted System controllers to the situation were not in place.

v) Despite the transient nature of the fault, the System went into unrecoverable instability and started cascading because the critical fault clearing time (CFCT) for the System (approximately 0.54 seconds) was exceeded and took place before the back-up protection relays (set to operate within 0.8 second) could operate to isolate the fault.

vi) The System shutdown occurred approximately 10 seconds after the fault took place.

8.2.1.2 Regulatory Action - 2006 July 15 Total System Shutdown

The OUR at the time indicated that the outage event exposed a number of deficiencies which unless addressed would continue to remain as potential enhancers of System outages. The OUR highlighted the need for specific System studies to identify other problematic areas. Importantly, the OUR also underscored the need for JPS to take action to upgrade its current operating practice and procedures, particularly in respect of the inspection and maintenance of the System's infrastructure and equipment, where presently deficient. Additionally, the OUR issued a number of crucial recommendations to JPS for implementation and also, to the IPPs at the time (JEP and JPPC).

A number of the recommendations were issued to JPS in the OUR's 2006 Directive[1], requiring the strict implementation of specific items.

8.2.2 The 2007 July 3 Total System Shutdown

Following the total System shutdown on 2006 July 15, in less than one year, on 2007 July 3, another major System failure occurred. The circumstances and causes were once more investigated by the OUR, reaching conclusions similar to those of the previous instance and issuing recommendations to JPS as to the appropriate corrective actions to be taken.

The incident resulted in the loss of 445 MW of load and caused customers island-wide to experience loss of electricity supply for time periods varying from under one (1) hour to eleven (11) hours.

8.2.2.1 Causal Factors - 2007 July 3 Total System Shutdown

The major causation factors associated with the outage were as follows:

i) The System shutdown was initiated by a two phase-to-ground fault resulting from a flash-over on JPS Old Harbour Unit #2 GSU transformer high voltage (HV) lightening arresters.

ii) Failure of one of the designated circuit breakers at the Old Harbour switchyard to open within the required time to clear the fault. The mal-operation of the circuit breaker was due to a stuck pole mechanism.

[1] Directive (Ele 2006/05) issued to Jamaica Public Service Company Limited pursuant to Section 4 of the Office of Utilities Regulation Act requiring remedial actions following the island-wide system shutdown of July 15, 2006

iii) The delay in the circuit breaker operation caused other local and remote protective relays which serve as backup in the event of a breaker failure but the System's CFCT had already been exceeded.

iv) A cascading effect ensued and all generating units on-line independently disconnected as a result of the initiation of generator protective relays due to frequency swings which were outside governor tolerances. Under the circumstances, the full shutdown of the electricity System was inevitable.

8.2.2.2 Regulatory Action - 2007 July 3 Total System Shutdown

Based on the enquiry into to incident by the OUR, the Office was of the view that this outage again revealed a number of problems which would have remained undetected but for the System collapse. The Office further indicated that the outage also underscored the requirement for further action on the part of JPS to promptly deal with certain items which were fundamental in instigating a System collapse such as the CFCT and the coordination of relevant protective relays. The need to inspect and maintain the System infrastructure and equipment was also clearly highlighted. Accordingly, the Office made a number of recommendations to JPS for implementation.

The Office also directed attention to previous recommendations it made in the OUR's enquiry report for the 2006 July 15 System Shutdown, in particular, those which required JPS to take action to upgrade its current operating practices and procedures, with specific focus on the inspection and maintenance of the System's infrastructure and equipment, where presently deficient.

The OUR at the time indicated that the contributing factors were addressed under specific recommendations by the PORT Study conducted as a result of the July 2006, System shutdown, which were identified for implementation by JPS.

8.2.3 The 2008 January 9 Total System Shutdown

The occurrence of this incident was the third occasion in less than eighteen (18) months on which the electricity System experienced a total collapse. The outage resulted in the loss of 420.5 MW of load and caused customers island-wide to experience loss of electricity supply for up 4 hours and 23 minutes. The Outage was again the subject of another OUR enquiry.

8.2.3.1 Causal Factors - 2008 January 9 Total System Shutdown

The major causal factors associated with the outage were as follows:

i) Investigations carried out by JPS immediately after the shutdown revealed that a pole supporting one of the transmission line conductors (wires) located less than two (2) miles from the Duhaney substation had toppled over, permitting current to flow from the conductor directly to the ground, precipitating an unstable condition since a short-circuit (fault) then developed.

ii) The protective devices intended to isolate faults on the transmission system operated correctly at the Duhaney substation, cutting off the flow of current from that substation to the fault location.

iii) At Tredegar the protective relays operated correctly but one of the two circuit breakers that were required to open in response to the relay signals failed to do so and fault current continued to flow from Tredegar to the fault.

iv) The first line of protection against the stuck circuit breaker condition did not operate, as the DC breaker supplying the relay circuits was switched off.

v) The second line of protection comprising back-up relay devices at the Old Harbour and Bellevue substations and on the transformer circuits at Tredegar responded to isolate the fault, but the response was slower than required.

vi) The sustained fault conditions caused the System voltage to collapse which in turn caused all generators island-wide to shut down and the entire System collapsed within about one minute after the fault had developed.

8.2.3.2 Regulatory Action - 2008 January 9 Total System Shutdown

Following the investigation of the outage by an Enquiry Panel established by the OUR, the Office again issued a number recommendations to JPS for implementation and emphasized the need for JPS to complete the implementation of recommendations from previous outages.

8.2.4 The 2012 August 5 Total System Shutdown

This incident was the fourth since 2006 in which the electricity System experienced a total shutdown. The outage resulted in the loss of 392.2 MW of load and caused customers island-wide to experience loss of electricity supply for up nearly 9.5 hours. The circumstances and causes of the outage were again the subject of another OUR investigation.

8.2.4.1 Causal Factors - 2012 August 5 Total System Shutdown

The major causal factors associated with the outage were as follows:

i) The System shutdown was initiated by a single phase (B)–to-ground fault, which transitioned to two phase-to-ground fault and finally a three phase -to-ground fault on the Duhaney - Naggos Head 69 kV transmission line.

ii) The primary line distance protection relay (MICOM P441) for the Duhaney – Naggos Head 69 kV transmission line trip circuit was out of service for four (4) months, and was unable to clear the fault which remained on the System for an extended period of (1.23 seconds).

iii) Remote line protection associated with the Duhaney – New Twickenham 69 kV line circuit breaker located at New Twickenham substation, which was required to open to isolate the 69 kV busbar at Duhaney substation, fail to operate.

iv) The transmission system was separated into two sub-systems following circuit breaker operations at Washington Boulevard, PAJ and Hunts Bay substations.

v) Transmission lines and generating units on-line tripped during the disturbance, which were followed by three stages of automatic UFLS before the System totally collapse.

8.2.4.2 Regulatory Action - 2012 August 5 Total System Shutdown

Following the investigation of the outage by an Investigation Committee established by the OUR, it again issued a number recommendations to JPS for implementation and emphasized the need for JPS to complete the implementation of recommendations from previous outages.

8.2.5 The 2013 March 30 Major System Outage

This incident resulted in the partial shutdown the electricity System during which, 392.2 MW of load was disconnected from the System causing customers in all parishes to experience loss of electricity supply for up 7.5 hours.

Although there were no formal investigation of this incident, it subsequently became apparent that there was only limited implementation by JPS of the recommendations that emanated from both the OUR's and JPS investigations of the 2012 August 5 System shutdown. Shortly thereafter, the country was reminded of the prevailing defects and deficiencies in the System by the outage in question.

8.2.5.1 Causal Factors – 2013 March 30 System Outage

i) The rupture of a newly installed 69 kV Voltage Transformer (VT) during commissioning tests resulting in a fault on the System.

ii) The 69 kV busbar 1 differential protection operated to clear the fault initiated by the ruptured VT in 62.5 ms. However, circuit breaker 020/8-930 at Duhaney substation operated improperly and tripped after the fault was cleared.

iii) The tripping of the Duhaney substation 69 kV busbar 1 circuit breakers resulted in the CA being connected to the Rural Area (RA) by one transmission path, that was, Hunts Bay – Port Authority – Duhaney 69 kV link. The tripping of the circuit breakers resulted in the loss of approximately 30 MW of load from the System.

iv) Approximately ten (10) seconds after the fault was cleared, Bogue GT12 and GT13 (components of the CCGT) at the JPS Bogue power station dumped approximately 5 MW and 8 MW respectively, before tripping on loss of flame condition. Approximately four (4) seconds later the water injection control systems tripped and restarted causing the units to flame-out and trip. ST14 (component of the Bogue CCGT) tripped 35 seconds after as a consequence of the loss of GT12 and GT13.

v) The loading on the Hunts Bay – PAJ 69 kV line increased from 163 Ampere to 450 Ampere and then to 712 Ampere subsequent to the trip of the Bogue CCGT. The Hunts Bay – PAJ – Duhaney 69 kV transmission link maintained the connection between the CA and RA for approximately two (2) minutes after fault clearance before it tripped on circuit overload by the operation of directional overcurrent protection at Hunts Bay substation (pick-up current – 720 Ampere).

vi) Upon the tipping of the Hunts Bay – PAJ – Duhaney 69 kV transmission link, the Power System separated into two sub-systems, the CA and RA sub-systems.

vii) The initial loss of load due to the isolation of the Duhaney substation 69 kV busbar 1 after fault clearance resulted in an increase in System frequency. However, the subsequent tripping of Bogue GT12 and GT13 resulted in an under-frequency situation with loads in stage 0 and stage 1 being shed. Other load shedding operation was activated in an attempt to stabilize the System.

viii) Immediately after the System separation, JPPC units tripped due to voltage balance protection while WKPP units tripped on governor over-frequency. JPS reported that these effects were the subject of further investigation.

ix) Following the disconnection of the JPPC units and the loss of the RA load, stages two (2), three (3) and four (4) UFLS occurred in the CA sub-system.

x) The blackout of the RA sub-system was precipitated by overload conditions triggered by low voltage and low frequency. The low voltage caused OH unit #3 and unit #4 to trip off-line and all other generating units in the JPS RE generation facilities in the RA sub-system. The OH unit #4 burner management system was impacted by the low voltage condition and JPS indicated that the situation was the subject of further investigation.

xi) The low frequency affected distance relays in the RA sub-system, specifically, relays for the Kendal-Spur Tree, Spur Tree - Maggotty, New Twickenham – Tredegar, Duhaney – New Twickenham, Tredegar – Michelton Halt, and Bellevue – LWR, 69 kV transmission lines. According to JPS, this situation was a matter for continued investigation.

Based on the available information, no major investigation was conducted for this outage. However, the extent of the problems highlighted, suggested that one was warranted.

8.2.6 The 2016 April 17 Major System Outage

This incident resulted in the partial shutdown of the electricity System during which, 485.03 MW of load was disconnected from the System causing customers in all parishes to experience loss of electricity supply for up 3 hours and 50 minutes.

8.2.6.1 Causal Factors – 2016 April 17 System Outage

i) The Hunts Bay - Duhaney and the Hunts Bay - PAJ 69 kV transmission lines were, out of service on planned outage (scheduled for 7:00 am to 6:00 pm) to facilitate National Works Agency (NWA) Road Widening Project along Marcus Garvey Drive.

ii) To facilitate safe working clearances to carry out the planned outage, the majority of customers supplied from the distribution feeders on the Hunts Bay T3 distribution transformer were all transferred to the Three Miles T1 distribution transformer. In the rural area there was one planned outage on a section of the Kendal 237/6-310 feeder that was projected to run from 9:00 am to 4:00 pm.

iii) The risks associated with a delayed return to service of both transmission lines was not given adequate focus by the System Operator.

iv) There was inadequate communication between System Operations and the Field Operation team, during outage execution.

v) The System Operator failed to conduct the necessary contingency analysis and to make allowance for a late start and other issues that might have developed during the execution of the planned outage, given the existing contingency conditions.

vi) The constraints in the outage plan provided to the System Control Centre was not clearly defined.

vii) At some instances, the actual generation dispatch deviated from what would have been the required optimal security dispatch.

viii) It was unknown to the System Controller that the load current for the Hunts Bay - Three Miles 69 kV transmission line, located at the Hunts Bay substation, was limited to a maximum of 600 Amps. This in turn compromised the Control Engineer's visibility of the actual transmission line power flow above 600 Amps.

ix) The Hunts Bay - Three Miles 69 kV transmission line tripped on overcurrent after the line current exceeded the maximum current limit.

x) The loss of the Hunts Bay - Three Miles 69 kV transmission line precipitated the subsequent trip on the West Kings House Road - Washington Blvd 69 kV line.

xi) The line trips resulted in the separation of the System into two sub-systems, the CA and RA sub-systems.

xii) The CA sub-system experienced an over-frequency condition due to the loss of 78 MW that was being exported to the RA sub-system prior to the separation in addition to the loss of 32 MW and 15 MW of customer demand from Washington Boulevard and Three Miles substation respectively. Thereafter, generating units in the CA sub-system, equipped with over-frequency and over-speed protection tripped off-line changing the System dynamics. This resulted in a massive power swing causing the System frequency to suddenly shift from high to extremely low and thereby causing under-frequency protection in stages 2-4 to operate to stabilize this sub-system.

xiii) The RA sub-system suffered from an overload condition following the separation from the CA sub-system and the 124 MW increase in customer demand that was transferred to the Rural Area sub-system. This sudden generation/load imbalance resulted in automatic UFLS points in stages 0-4 operated with some UFLS relays failing to operate. The rising customer demand, coupled with the failure of some under-frequency points to operate, contributed to the further decay in the System frequency, and the subsequent tripping of generating units in the RA sub-system on low frequency, and eventual blackout of this sub-system.

xiv) The Hydro generator breaker trip times are not Global Positioning System (GPS) time synchronized nor visible in SCADA.

xv) JPPC unit #2 and JEP Barge # 2 generator breakers are GPS time synchronized but not visible in SCADA.

The circumstances and causes of the System outage were again the subject of another OUR investigation.

8.3 Common Factors among the Major System Outages

There were several factors common to some of the previous major System failures that occurred in Jamaica and the 2016 August 27 System outage. These include:

- Failure of protection systems to operate as required to isolate faults and prevent System instability.
- Lack of proper coordination of protection relays and other protective devices or apparatus
- Inadequate maintenance of critical System components
- Inadequate planning and coordination, particularly with planned outages
- Awareness and training of operating personnel
- Failure to ensure operation within secure limits
- Lack of full visibility over the Power System
- Lack of proper communication and coordination between the System Control Center and Field Personnel

Notably, some of the problems that emerged in the 2016 August 27 System shutdown, were also identified from as far back as 2006. Some of these problems were also featured as part the 2006 PORT recommendations and OUR Directives issued to JPS for implementation. However, they continue to surface in almost all the subsequent outages without being remedied.

9 OBSERVATIONS, FINDINGS AND COMMENTS

The island-wide Power System shutdown of 2016 August 27 has illuminated a number of problems adverse to reliable System operation which unless addressed, will continue to remain as potential contributors to future System failures.

The issues identified during the investigation are addressed in section 9.1 below.

9.1 Details of Observations and Findings

The details of the observations and findings are as follows:

9.1.1 Operational and Procedural Issues

1) During the planned maintenance outage at the PAJ 69 kV substation, the System Operator's maintenance personnel did not remove one (1) of five (5) "short-and-ground" that were installed on the 69 kV transmission system in the vicinity of breaker 169/8-130 at the PAJ substation to facilitate the maintenance work. This omission precipitated a solid three phase-to-ground fault on the System upon the re-energizing of the Hunts Bay - PAJ 69 kV transmission to return the System to normal operation, which eventually resulted in the total collapse of the Power System.

   The failure to remove the "short-and-ground" from the System is a clear departure from the applicable switching procedures, relevant safety rules and prudent utility practice, and constitutes a deviation from the Licence requirements.

2) There was ineffective coordination between the System Control Center and the maintenance crew and this created the conditions for the occurrence of the solid three phase-to-ground fault on the 69 kV transmission system.

   Following the completion of the planned maintenance work at the PAJ substation, the System Operator personnel did not take the necessary actions to return the System to normal operation in a safe and reliable manner. According to the System Control Report (Appendix D of the "Technical Report"), there were communication challenges between System Control and the maintenance personnel. The communication records between System Control and the maintenance personnel were requested from JPS and were to be included as part of the report required under the EA on 2016 September 28, and despite several reminders, these records were not submitted to OUR until 2017 February 22. Refer to section 9.3 of this Investigation Report for details on this matter.

3) JPS did not provide the OUR with sufficient evidence to demonstrate that all the maintenance personnel involved with the work assignment were appropriately trained and qualified as stipulated by Condition 9, paragraph 1 of its Licence.

   Based on supplementary information provided in the 2016 September 28 submission, it was revealed that only one of the maintenance personnel out of the maintenance member crew appeared to have participated in Switching Authorization Programme and T&D Tag-out Programme. No documentary evidence was provided that the other maintenance personnel were appropriately trained and qualified to carry out such crucial maintenance activities and procedures on the System's critical components.

   In "JPS comments on the Draft Report of the OUR's Investigation into the August 27, 2016 System Event" submitted to OUR 2017 February 27" ("JPS Comments"), JPS posited that:

   > *"All members of the maintenance crew are trained and certified employees to conduct work on the JPS System. Their experiences ranges from 2 to 14 years. Each switching personnel on the maintenance crew was exposed to the requisite switching training required to switch at the transmission level and for the job they were executing. Training records and Switching and LOTO Policy will be made available to the OUR presently."*

   However, no additional training records and switching and LOTO policy mentioned in JPS' comments have been subsequently submitted to the OUR.

4) The Substation Department Job Order (SDJO) documentation provided by JPS was found to be deficient in certain aspects. These include, controls for the LOTO PTW requirements, consistency with personnel assigned, identification and accountability of personnel designated to conduct specific tasks, and importantly, validation and responsibility for safety measures or procedures undertaken.

   - There were nine (9) persons listed on the SDJO to execute the maintenance assignment but only six (6) of the persons listed signed on to carry out the works. One additional person signed on who was not included in the list of human resources on the SDJO.

- According to the T&D Report (Appendix C of the "Technical Report"), the designated maintenance crew which entered the PAJ substation consisted of five (5) substation personnel, two (2) protection & Control personnel and one (1) transmission line personnel. This accounts for a maintenance crew of eight (8) personnel which is inconsistent with the evidence on SDJO which shows that only seven (7) persons signed on to execute the works. Three (3) of the maintenance crew who signed on did not sign off.

- The said T&D Report indicated that the maintenance crew arrived at the PAJ substation approximately after 9:00 am due to delays caused by vehicle problems and access to the PAJ compound. The Tailboard conference was held and LOTO Permit to Work issued after.

- The T&D Report revealed that the maintenance crew agreed to apply "short-and-ground" at the following locations:

  #1 - Downdropper of Isolating switch 169/8-137
  #2 – circuit breaker 169/8-430 isolating switch 169/8-439
  #3 - HV terminal of Transformer T2
  #4 - LV terminal of Transformer T2
  #5 - Incoming 69 kV line from Hunts Bay.

- Four (4) of the "short-and-ground" were placed as indicated, however the one associated with 169/8-137 was actually placed on downdropper to circuit breaker 169/8-130 without the knowledge of the authorized person responsible for the job.

- It was indicated that the LOTO PTW was issued at about 10:30 am, after which, the maintenance work commenced. Notwithstanding, according to the Operations & Planning Report (Appendix A of the "Technical Report"), the planned maintenance work was scheduled to start at 7:00 am and finish at 6:00 pm.

- Maintenance work on transformer T2 and circuit breaker 169/8-430 was completed before that scheduled for isolating switch 169/8-251 and the "Circuit Breaker and Transformer" team removed the "short-and-ground" #3 and #4 from HV and LV terminals of transformer T2, signed off from the Tailboard, and left the site. When the work was completed on isolating switch 169/8-251, the "Isolating

Switch" team proceeded to remove the associated "short-and-ground" #2 and #5. In executing the clearance procedure of the LOTO PTW, the team did notice that "short-and-ground" #1 was still connected to the System on the downdropper to circuit breaker 169/8-130. Ignorant to this fact, the authorized personnel proceeded to cancel the permit. The 69kV bus was then energized with "short-and-ground" #1 still connected to the System creating a three phase-to-ground fault.

- In the report submitted 2016 September 28 as required by the EA, including the OUR's "Information and Data Request", JPS did not provide all the relevant supporting evidence of the actions of the System Control Center, who has the responsibility for the operation, monitoring and control of the System, in verifying that the LOTO PTW was appropriately cleared, including the removal of the five (5) "short-and-ground" installed during the planned maintenance on 69 kV Transmission System which was under its direct supervision.

9.1.2 Protection System Performance Problems

1) The primary protection scheme failed to trip the relevant circuit breaker to clear the fault as expected. The situation was that the Enhanced Primary "A" high-speed Switch-Onto-Fault (SOTF) protection scheme failed to isolate the fault within the specified time of 100 ms.

   JPS reported that the malfunction of the SOTF protection scheme was due to a defective cable associated with status indication for circuit breaker 265/8-250 auxiliary "a" contact, which was replaced.

2) The back-up definite time directional overcurrent voltage dependent protection (MICOMM P141) relay with time delay of 250 ms failed to isolate the fault within the designed time.

   JPS reported that the failure was due to relay pick-up/drop-off chatter for a period in excess of 90 ms, which extended the trip time beyond the designed time. JPS indicated that the relay was subsequently tested and found to be defective and replaced. It is to be noted that the System experienced previous problems with the reliability of the MICOMM relays.

3) The Hunts Bay - PAJ Primary “A” and “B” zone 2 distance protection, operated correctly to clear the fault after approximately 433 ms. However, by that time, the System was tending to an unstable state.

4) The automatic UFLS scheme operated in an effort to maintain generation/load balance but could not be achieved due to the significant loss of generator units relative to the load/demand. During the incident, two (2) points in the UFLS scheme at the Hope substation failed to operate. However, the technical analysis revealed that, under the conditions, such failure did not trigger any significant adverse effect or exacerbated the situation, since the System was already in a state of uncontrollable instability and inevitable shutdown. Notwithstanding, the reported causes of the non-operation of the UFLS points, bring into focus, the issue of maintenance of critical System components and importantly, the capacity of the System Operator to become immediately aware of apparatus/equipment related defects.

9.1.3 Issues related to System Parameters and other Requirements

9.1.3.1 Spinning Reserve Issue

Based on the indicated available generation capacity relative to the System demand at the time of the incident, it was evident that the spinning reserve capacity that was in effect was not at the required minimum level stipulated in Schedule D of the Generation Code (2013 August), applicable at the time. It was also found that the spinning reserve was not proportionately distributed across the generating units online.

In “JPS Comments”, the company contended that:

> *“The Spinning Reserve of the system at any point in time is governed by JPS Operating Policy and Procedure (April 2013 revision), and the Economic Dispatch. The Policy dictates that spinning reserve should be operated within the range of 10 MW to 30 MW. While Economic dispatch determines the optimal distribution across active generating units. At the time of the incident, both the policy and economic dispatched were fully observed.”*

However, JPS’ interpretation of the spinning reserve as set out of above appears to be at variance with the stipulation of the Generation Code (2013) as shown in Figure 3.3. Moreover, the provisions for spinning reserve in the Jamaican Electricity Sector Book of Codes which was promulgated, after the occurrence of the outage, on 2016 August 29 do not reflect any amendment or alteration to the spinning reserve policy that was included in the Generation Code (2013) and are also at variance with JPS' position presented in their comments.

The spinning reserve margin that was in effect at the time of the outage (25.07 MW) was lower than the required minimum level of 30 MW to meet the daily System demand. This situation was a clear deviation from the approved Spinning Reserve Policy.

It is important to note that, subject to the legal and regulatory framework, JPS is obligated to plan and operate the System in conformance with the relevant System security standards and requirements.

9.1.3.2 SCADA and Communication System Functionality

The investigation revealed that a number of substations were affected by loss of SCADA visibility and communication capability after the System shutdown incident. The substations/sites affected by loss of SCADA visibility and communication services include: Port Antonio, LWR, Rockfort, Goodyear, Parnassus (B), Hunts Bay, Hope, and Spur Tree (A).

The loss of SCADA communication to some stations necessitated the employment of manual switching by field personnel which appeared to have delayed the restoration of the System. A temporary disruption to land-telephone system further impacted the restoration of the System.

It is accepted that an electricity network may not be able to achieve 100% SCADA and communication availability under all System conditions, even with adequate redundancy incorporated. Factors such as equipment maintenance and contingencies will occur from time to time that may impose constraints on those systems. However, reliable operation of the Power System is fundamental, and as such, the System Operator has the responsibility to ensure that the relevant facilities which are integral to the operation are appropriately designed, implemented and maintained in order to achieve this objective.

In the "JPS Comments", the company argued that telecommunication carriers in Jamaica do not offer greater than 99.7% availability which would be a constraint on any target JPS can be held to as the company contract for some service from these carriers. This implies that JPS has set a minimum availability of 99.7% for its SCADA and communication systems. Notwithstanding, consistent with the requirements of the Licence and good industry practice, JPS is required to ensure that this system is accorded the utmost priority in order to effect full operating status at all times.

9.1.3.3 Time Synchronization and SOE Issues

The investigation revealed that significant discrepancies in relation to Time Synchronization still exist at various locations in the System. This is considered to be a major concern for the proper operation and monitoring of the System. It also presents significant challenges when conducting technical analyses on the performance of the System, including investigations such as the one in question, where an accurate and precise account of the sequence of events is required, in order to facilitate a clear and comprehensive understanding of a particular circumstance, operating condition or incident.

It is important to note that Time Synchronization issues were identified as far back as 2006 during the OUR Enquiry into the JPS Power System Shutdown of 2006 July 15. OUR's Directives to JPS in relation to the System shutdown of 2006 July 15 required JPS to:

> *"Ensure that all JPS generating stations, IPP plants and JPS System Control Centre are time-synchronized and fully operational".*

In "JPS Comments", the company stated that:

> *"Time Synchronization has been implemented fully on the Transmission System and is operational but implementation is outstanding at some generating stations, inclusive of the RE plants..."*

<u>Time Synchronization and SOE issues identified during the investigation</u>

The issues include:

- Disparities with the time references (eg. fault inception time – [17:42:20.70]) given for the, SOE records, DFR records and those shown in the oscillography generated by the Hunts Bay – PAJ Primary "B" zone 2 distance protection relays (fault inception time - [17:45:14.354018]). This brings into question the issue of time synchronization.

- Different oscillography for relays from the same protection scheme shows variation in the "relay GPS time" this raises questions as to the plausibility of the times obtained from distance relay Primary "A" as opposed to Primary "B".

- It appeared that there was a degree of selectivity with the acceptance of the SOE records on which most of JPS' analyses of the incident was based. This was evident in the case of the JPPC Units trip times which were accepted as credible and used in the System Stability Analysis. However, the SOE times given for fault clearance was classified as secondary by JPS. Following that logic, then the recorded times for JPPC Unit trips and other events captured by the SOE should also be considered as secondary.

- There were apparent gaps between the SOE times and those from the DFRs and Relays. However, there was no indication of any attempt to reconcile the times to ensure that a credible and representative SOE to clearly reflect what actually transpired during the incident.

- There was no clear explanation for the difference in fault clearing time of 433 ms and 543 ms. According to JPS, the total precise fault duration of 0.433645 second, all other time sources are secondary due to latency within the SOE communication devices. The issue is, if time difference is due to latency, then the resulting errors would be 110 ms or (25%), which is greater than 100 ms required for operation the primary protection.

- The GEN -PLANTs Report (Appendix B of the “Technical Report”) shows trip times for JPPC Units which implies that the generation facility is not time-synchronized.

- Relay oscillography for WKPP provided in section of 7.1.2 of the “Technical Report”, indicates that the fault duration was 698 ms

- DFR oscillography for WKPP shown in section 7.1.2 of the “Technical Report”, indicates there may be components at the facility that are not time-synchronized.

9.1.3.4 DFR Calibration Issues

The investigation revealed that there were time settings and calibration issues that were associated with some DFRs installed in the System.

9.1.3.5 Critical Fault Clearing Time

It was found that both the “Technical Report” and JPS’ Transient Stability Analysis (dated 2016 October 31) did not definitively address the issue of the critical fault clearing time (CFCT) in relation to the incident.

In the Transient Stability Analysis, JPS indicated that the critical fault clearing times were calculated for the generating stations at JPPC, WKPP and RF#1 based on the loading and system configuration at the time of the fault. The CFCTs were calculated based on a three phase to ground fault on the generator busbar for each of the three stations named above as well as on the Hunt's Bay to PAJ 69 kV line at PAJ Substation. The results as presented by JPS are shown in Table 9.1.

Table 9.1: JPS Calculated Critical Fault Clearing Time

Fault Location	Power System Status	Critical Fault Clearing Time – Fault on Generator Bus (ms)	Critical Fault Clearing Time – Fault at PAJ (ms)
JPPC	Loading and system configuration at the time of the fault.	443	1997
RF1		215	1997
WKPP		175	1997

Source: JPS Transient stability Analysis of Three Phase –to-Ground Fault on PAJ 69 kV Busbar - dated 2016 October 31

The information provided, indicates that the CFCT for a fault at PAJ is 1997 ms (99.9 cycles).

Based on the CFCTs provided in the supplementary information included in the report submission (2016 September 28), there is no 69 kV busbar in the System with such a high CFCT. (Refer to Table 9.2)

Table 9.2: CFCT at 69 kV Busbars

CRITICAL CLEARING TIME SUMMARY		
BUS	BUS VOLTAGE	CYCLE
Hunts Bay	69kV	11
Duhaney	69kV	13
Bogue	69kV	14
Rockfort	69kV	10
WKPP	69kV	10
Cane River	69kV	26
Bellevue	69kV	22
Washington Blvd	69kV	15
Three Miles	69kV	16
Maggotty	69kV	17
Queens Drive	69kV	18
Roaring River	69kV	18
Hope	69kV	25
Up Park Camp	69kV	13
Upper White River	69kV	15
Lower White River	69kV	15
Cement Company	69kV	15
Greenwich Road	69kV	15
Duncans	69kV	25
Maggotty	69kV	17
Queens Drive	69kV	18

Source: JPS Supplementary Information to the JPS Major System Incident Technical Report (Critical Clearing Time Study, 2013 Feb) - dated 2016 September 28

Given the issues outlined in section 7, compounded by the concerns presented above, CFCT evaluations are classified as indicative, and does not provide sufficient grounds for any specific conclusions in relation to this incident. As such, further evaluation and analysis of this issue will be required.

9.1.4 System Restoration Issues

It appeared that System restoration was not executed in an efficient and timely manner, given the identified impediments. It was also found that there were several instances of delays during the process which was due to recurring problems such as Black Start capability, communication and network visibility, among others.

9.2 Corrective Action Taken By JPS

According to the "Technical Report", the corrective actions taken by JPS following the incident are shown in Table 9.3.

Table 9.3: Reported Corrective Actions taken by JPS

Corrective Actions Already taken by JPS following the 2016 August 27 System Shutdown			
PROBLEM	**CAUSE**	**ACTION TAKEN BY JPS**	**STATUS**
Non-operation of the UFLS points at Hope Substation	Blown Fuse	Replaced two blown 125V DC fuse	Completed
Non-operation of SOTF scheme for the primary "A" distance protection	Defective cable	Replaced defective control cable	Completed
Non-operation of the Hunts Bay-PAJ line directional overcurrent protection.	Defective device	Replaced defective MICOMM P141 relay for the Hunts Bay -PAJ line	Completed
Relay settings at PAJ		Implemented setting modifications at PAJ to accommodate Echo logic in the Permissive Overreaching Transfer Trip (POTT) scheme with a view to increasing the speed of the communication assisted POTT scheme when the line is energized while line breakers are open.	Completed

10 CONCLUSIONS

The Review Team has formed a number of conclusions regarding the specifics of the 2016 August 27 outage, but in the context of a broad terms-of-reference it has concluded that the System is subject to issues regarding:

i) System instability and protective relaying shortcomings;
ii) Proper planning and coordination of System operations;
iii) Maintenance approach;
iv) Compliance with operating procedures and processes;
v) Awareness and training of operating personnel.

The major conclusions specific to the 2016 August 27 outage are summarized as follows:

1) The System shutdown was initiated due to the failure of the System Operator's maintenance personnel to remove a "short-and-ground" that was installed on the 69 kV Transmission System in the vicinity of breaker 169/8-130 at the PAJ substation, to facilitate maintenance work at the substation. This precipitated a solid three phase-to-ground fault on the System upon the re-energizing of the Hunts Bay - PAJ 69 kV transmission to return the System to normal operation.

2) The primary protection scheme failed to trip the relevant circuit breaker and clear the fault as was expected.

3) The relevant Back-up protection scheme failed to clear the fault as was expected.

4) Primary "A" and "B" zone 2 distance protection operated as designed to clear the fault after a reported time of 433 ms.

5) The fault clearance after 433 ms resulted in unstable Power System conditions and caused the tripping of all on-line generators in the CA, which precipitated a cascading effect and eventual collapse of the System after approximately 15 seconds.

6) Several generating units were affected by the instability occasioned by the large power swings and the low busbar voltages and their inability to ride-through low voltage condition during System faults.

7) The early tripping of JPPC and WKPP units contributed the outage, by exacerbating the situation that triggered the System cascade which eventually led to the total System shutdown.

8) The non-functioning of a number of important communication systems during the System shutdown, affected the early analysis of the problem and therefore delayed restoration activities.

11 RECOMMENDATIONS

11.1 Recommendations applicable to the OUR

The recommendations to be considered for implementation by the OUR are as follows:

1) Promote and encourage the implementation of enforceable standards and requirements through the framework of the Jamaica Electricity Sector Book of Codes and other relevant regulations to govern the operation and control of the Power System as well as the maintenance of System components with focus on critical plant, equipment and apparatus.

2) Consider an approach to incorporate a separate reliability performance measure to address the effects of major System outages determined to be within JPS' control, as a component of the QoS requirements. This may involve compensation to customers affected by a major System failure such as the 2016 August 27 incident, which would provide a further incentive to the System Operator to ensure that its actions or operations do not adversely impact System reliability.

3) Establish an appropriate framework for the collection and reporting of data needed for post-blackout analyses, and for JPS and IPPs to preserve evidence as far as is possible, after a System shutdown incident.

4) Improve the existing monitoring framework to enable it to appropriately track the implementation of recommendations resulting from investigations in relation to major System failures or conditions impacting System reliability, issued by the regulator to the System Operator.

5) Through the medium of the existing regulatory mechanisms, ensure that JPS executes all the corrective actions indicated in the "Technical Report" submitted 2016 September 28.

11.2 Recommendations to JPS

The recommendations to be implemented by JPS are as follows:

1) Implement the recommendations emanating from the OUR's investigation of the 2016 April 17 System outage, in accordance with the developed Action Plan.

2) Ensure that adequate measures are introduced to forestall and prevent the recurrence of problems associated with the 2016 August 27 System shutdown, including the issues associated with the performance of the IPP's generation facilities

3) As a matter of priority, review the current switching procedures and safety rules and establish appropriate systems to ensure compliance.

4) Urgently review the policies and procedures governing all communication between System Control and Field Personnel to ensure greater accountability. Also, maintain a sound Records Management & Storage system to ensure that all communications between the System Control Centre and other operations personnel, can be properly recorded and protected, and can be accessible to the regulator to facilitate necessary investigations and audits.

5) Review and improve the T&D maintenance policies and procedures, including the SDJO and the LOTO PTW system to ensure greater accountability.

6) Urgently review operating guidelines to ensure that the System is returned to normal and reliable operation in a timely manner following a contingency event.

7) Review the training and certification requirements for all personnel involved with the operation, monitoring and maintenance of the T&D system with a view to closing any skills or competence gaps that may exist. This will require that the relevant operations & control personnel are engaged in on-going operational training, including appropriate certification training in switching and safety procedures.

8) Implement mechanisms or upgrade existing monitoring systems to ensure that System Control, the relevant maintenance personnel and management can be immediately alerted of defects which develop on critical equipment/apparatus.

9) Urgently investigate the SOTF protection scheme currently incorporated in the primary “A” distance protection and all other critical protections systems at all the relevant substations in the System to identify defects or maintenance issues, and take the necessary corrective actions to remedy identified weaknesses.

10) Urgently evaluate the primary distance protection at Hunts Bay substation and all other relevant substations in the System and incorporate the SOTF scheme in the primary “B” distance protection as a means of redundancy to improve System resilience and reliability.

11) Conduct an evaluation of the set-up, functionality, settings, coordination and maintenance practices of the protective relaying schemes installed in the Power System, as well as, resource adequacy and competence of System protection personnel. JPS may wish to share the TOR developed for the evaluation with the OUR for review, and on completion of the evaluation, a copy of the final report shall be submitted to the OUR.

12) Conduct a comprehensive assessment of the unacceptable LVRT performance of some interconnected generation facilities (JPS and IPPs) duration System disturbances, including low voltage protective schemes and settings; and make specific recommendations and take actions to guarantee that the generating units do not trip off-line spuriously and unnecessarily during major System disturbances. A copy of the report of this assessment should be made available to the OUR.

13) Require of JPPC, consistent with its interconnection agreement, to (a) correct the specific cause of the reported early tripping of its generating units on low voltage (b) take action to get the facility time synchronized.

14) Conduct Transmission System assessments and review existing T&D system studies to (a) evaluate any apparent need to upgrade and re-reinforce the 138 kV transmission network so that robust direct links are available to connect the major generating facilities directly to each other, to enhance System reliability and resiliency and reduce the possibility of System separation during major System disturbances, and (b) ensure that sufficient redundancy is embedded in the System to support optimal power flow and accommodate the System security contingency criteria stipulated in the Jamaica Electricity Sector Book of Codes.

15) Comprehensively review the overall UFLS Scheme protection scheme, with emphasis on feeder/load characteristics for peak, partial peak and light load conditions. Also, carry out

the appropriate maintenance activities on the overall automatic UFLS relay scheme to eliminate potential problems that could contribute to its mal-function or non-operation as was the case at the Hope substation during the System shutdown on 2016 August 27.

16) Conduct analysis or update relevant existing studies to determine the CFCT on the various transmission lines in the System. Also, ensure that the maximum fault clearing time setting for primary and back-up protection at all substation busbars deemed critical to System security does not exceed the determined CFCT for each busbar or transmission lines.

17) Review and evaluate the existing spinning reserve policy to ensure reliable System operation under normal operating conditions and contingency scenarios. A copy of the evaluation report shall be submitted to the OUR. In the interim, JPS will ensure that the spinning reserve allocated to the designated generating units is fully functional and can be efficiently deployed subject to the minimum specifications of the respective generating unit.

18) Take the necessary action to improve the quality of System modeling data to facilitate, inter alia, the proper post-event analyses of System performance for incidents such as the 2016 August 27 System shutdown.

19) Investigate and upgrade the communication systems as appropriate and ensure that the systems are properly maintained. Also, complete the implementation of plans for full redundancy of alternate communication signal and data routing in the event of failure of the default channel.

20) Ensure that all the SOE recorders installed in the System are made fully functional and kept in a serviceable state at all times.

21) Ensure the availability and reliability of all DFRs installed in the System and take appropriate measures to ensure that they are properly calibrated and maintained on an on-going basis.

22) Pursuant to Item 9 of the OUR's 2006 Directive pertaining to the 2006 July 15 System shutdown, take immediate action to ensure that all JPS generation stations, IPP generation facilities, JPS System Control Centre and other relevant sites in the System are time synchronized. A report on the approach to be undertaken by JPS shall first be

submitted to the OUR, after which periodic progress reports shall be submitted to the OUR based on an agreed schedule.

23) Ensure that full SCADA visibility of monitored and controlled System equipment/apparatus is a priority and that the availability of the SCADA system is consistent with international best practice, whether during; normal operation, a shutdown event or System restoration. In addition, JPS shall revise its maintenance programme for this system and shall lodge a copy of this programme with the OUR.

24) Develop an appropriate framework for the routine inspection and maintenance of all "Black Start" facilities/equipment on the System. Reports on the inspection and maintenance activities shall be submitted to the OUR as part of the "monthly technical report" submitted by the System Operator to the OUR.

JPS is required to provide a report to the OUR on the actions taken regarding the implementation of these recommendations.

11.3 Recommendations to IPPs

The recommendations applicable to the IPPs are as follows:

1) Ensure that all generation facilities equipped with Black Start facilities are kept in an available state with the start-up machines in good working order.

2) Cooperate with JPS or its agents or consultants in the performance of the required studies/assessments in relation to LVRT capabilities of the relevant generating units and other requirements critical to System reliability security.

3) JPPC is required to investigate and correct the specific cause of the reported early tripping of its generating units on low voltage, taking into account, the Interconnection Criteria and other relevant provisions included in the Jamaica Electricity Sector Book of Codes.

4) JPPC is to immediately take action to ensure that its generation facility is time-synchronized with the System.

5) Subject to the Interconnection Criteria in the Jamaica Electricity Sector Book of Codes, WKPP is required to investigate and address the early tripping of its generating units as well as the apparent inability of the units to export active power under abnormal operating conditions.

6) JEP and WKPP in collaboration with JPS are required to perform load rejection tests at their respective generation facilities to determine the responsiveness of the generating units when subjected to abnormal System conditions.