Voltage Collapse System Protection Increases Power Transfer Limits at the Panama Transmission System

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***Abstract*—Panama's transmission system has geographical and infrastructure constraints that make it very susceptible to different contingencies that have led to major blackouts affecting loads at Panama and the Central American transmission system over recent years. ETESA – CND developed a special protection scheme that takes remedial actions to increase reliability while keeping or increasing power transfer limits to allow for the most economical operation. Most hydroelectric power and Central America connections are in the west of the country, and the largest loads, like Panama City or Panama Canal, are in the east. Power flows from west to east, reaching voltage stability transfer limits when there is high hydroelectric generation. The load center operates too close to the power-voltage (PV) curve limit. The system cannot withstand some single line, double line, or generation contingencies without the remedial actions or without limiting hydroelectric generation and increasing generation cost.**

This paper presents the main challenges found during power system studies and provides remedial action solutions implemented using modern technologies and wide-area, high-speed communications. For this power system and its operating conditions, there is no time to evaluate voltage stability indexes or develop PV curves in real time to take preventive actions. Some contingencies would lead to instantaneous voltage collapse or fault-induced delayed voltage recovery (FIDVR) and may shed load in an uncontrolled manner. Very fast load-shedding actions are needed, so a contingency-based scheme is proposed and implemented. Load-shedding needs to be adaptive and to optimize the amount of load to be shed to maintain system stability. The load-shedding design adapts the amount of load to shed depending on the main transmission corridor power flow for line contingencies. The scheme additionally adapts to changes on local generation for generation contingencies, and the load-shedding amount is limited to avoid other consequences on the Central American interconnection link. Extensive real-time, hardware-in-the-loop (HIL) digital simulations were conducted to validate the implementation.

I. Introduction

Empresa de Trasmisión Eléctrica SA (ETESA) is the Panama state-owned company in charge of Panama's transmission system. Centro Nacional de Despacho (CND) is a subsidiary of ETESA that coordinates power system operations and national and regional market transactions in charge of the national control center. Panama's power system operates as an open market with several generation and distribution companies. During recent years, both demand and generation have grown fast while the development of transmission capacity, including lines and static volt-ampere reactive (VAR) compensation projects, have suffered delays for different reasons. The Panama transmission system operates closer to their transfer limits, leading to reduced security margins or limited economic dispatch.

Panama's power system has unique geographical conditions that make system operation challenging. Fig. 1 shows Panama's transmission network.

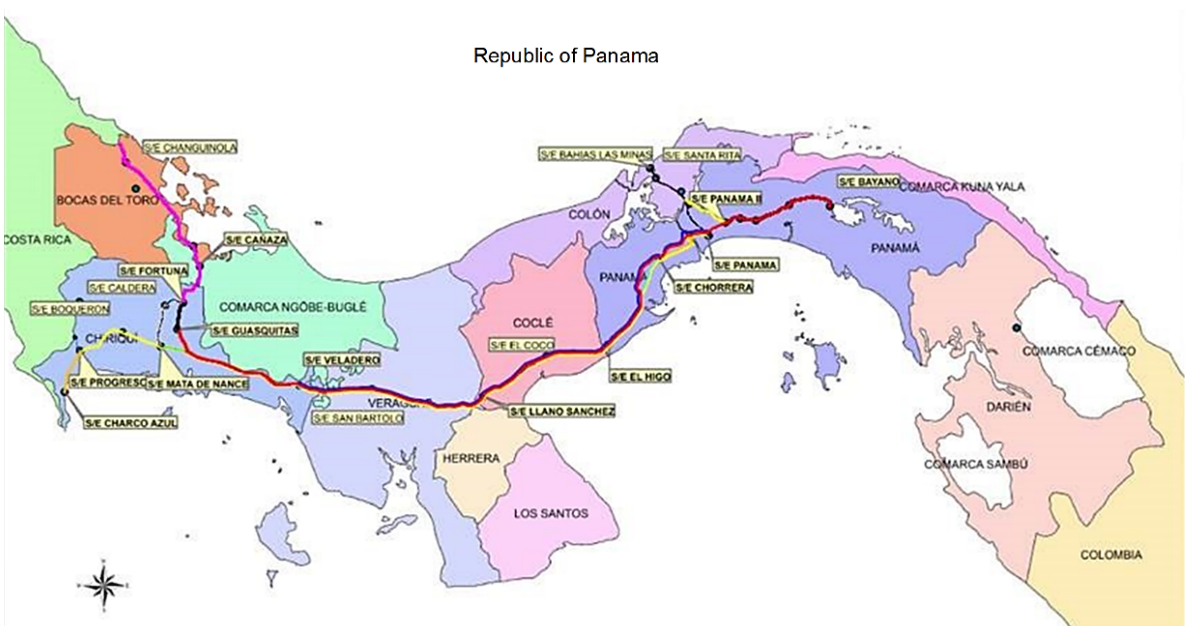

Fig. 1. Panama transmission lines, (geographical view).

The biggest load centers, like Panama City, the Panama Canal, and other industrial zones, are in the east of the country. Major hydroelectric generation capacity and interconnections to the regional Central America power system are on the west. The main transmission corridor is around 400 km of 230 kV lines long, from west to east, with typical longitudinal system problems, including transmission transfer limitations because of voltage stability issues that will be described in Section III.

Panama is at the end of the regional Central American system that also connects to Mexico. There is no connection to South America. Fig. 2 shows the geographical location of each country and its corresponding relative size measured as generation capacity connected to the system during the first phase of the project (2020).

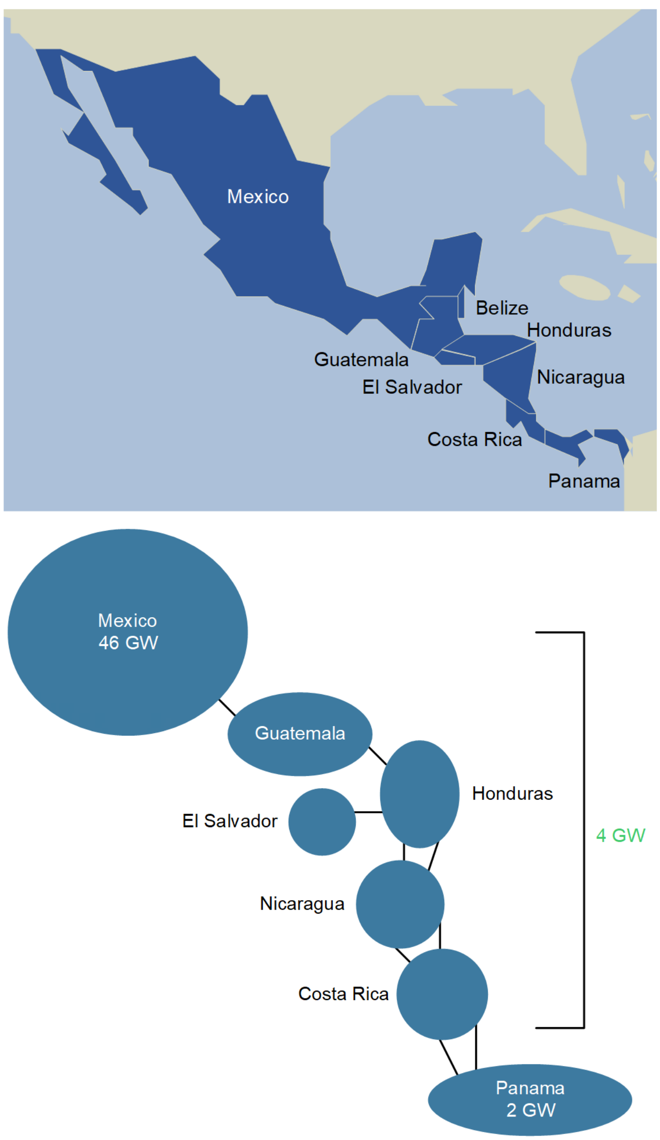

Fig. 2. (a) Geographical location of each country and their relative generation capacity connected and (b) relative size of interconnected power systems. Central America, Panama, and Mexico.

Because of the large difference in power system sizes and inertias between the Mexico and Panama systems, every change of load or generation into Panama system directly affects load flow from Mexico to Panama. The described behavior causes different operation and coordination challenges and several events in the interconnected system that occurred in recent years caused major blackouts or affected large blocks of generation or load, not only in Panama but in all the neighbor countries. ETESA – CND decided to implement a new wide-area protection scheme that takes remedial actions for different contingencies to maintain stability without over-limiting power transfer limits, which affect economic dispatch. In this paper, we will present only contingencies related to voltage stability problems. Future work will show other types of effects that are part of the same system.

II. Voltage Stability and Voltage Collapse Concepts

A. *Steady-State Analysis*

Fig. 3 shows a simplified power system model where a voltage source with magnitude V_S supplies a remote load through a transmission line impedance. Notice there is no generation on the remote end for this simplified model and there is no angular stability transfer limit. [1] develops simplified maximum power transfer equations that help to understand the voltage collapse problem.

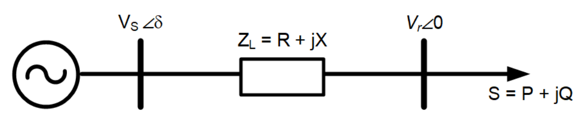

Fig. 3. Simplified power system model with a generation source, transmission impedance, and remote load.

Equations (1) and (2) define active and reactive power transfer as a function of source and the remote end voltage, impedance, and voltage angle difference between source and load. These quadratic equations define curves that have two solutions for each remote end voltage values, as shown in Fig. 4.

$$P = \left[\left(V_s \cos\delta - V_r \right) \frac{R}{R^2 + X^2} + V_s \sin(\delta) \frac{X}{R^2 + X^2} \right] V_r \quad (1)$$

$$Q = \left[\left(V_s \cos\delta - V_r \right) \frac{X}{R^2 + X^2} - V_s \sin(\delta) \frac{R}{R^2 + X^2} \right] V_r \quad (2)$$

Fig. 4 graphs active power solutions versus voltage at the remote end for two different reactive load conditions. These types of graphs are known as power-voltage (PV) curves or nose curves and are basic tools for steady-state transfer limit analysis. The maximum transfer limit marginally stable operating point is known as the bifurcation point.

Equation (3) is a simplified equation to calculate maximum apparent transfer power S_{max}. Maximum active power P_{max} can be calculated assuming constant reactive power (Q) at the load. Maximum reactive power Q_{max} can be calculated assuming constant active power (P) at the load. Maximum transfer is proportional to the square value of source voltage (V) and the inverse of line or transfer reactance (X). If a simplified model assumes X >> R, then the R effect is neglected.

$$S_{max} = \frac{(1-\sin(\Theta))\,V_s^2}{2\cos(\Theta)^2\,X} \quad (3)$$

where:

Θ is the load power angle

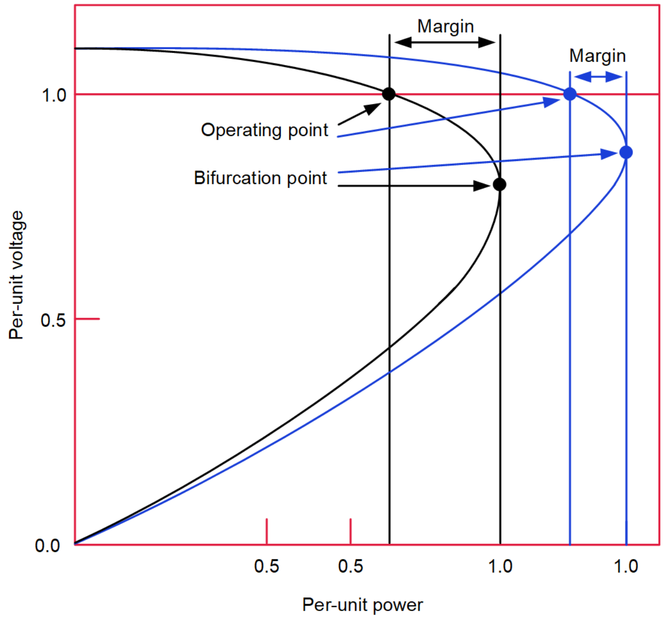

Fig. 4. PV curves with and without additional reactive compensation on the remote end.

The voltage at the source should be close to 1 per unit in normal operating conditions. Reactance on a transmission corridor depends on the number of lines in service. Its value is constant when all lines are in service, and it is bigger when there are contingencies and lines out of service, reducing the transfer limit. The third variable affecting maximum transfer is the load power angle Θ. The black curve in Fig. 4 shows active power with initial values of reactive power load. It shows typical behavior when the nominal voltage operating point is far from the bifurcation point. Power limit happened at very low-voltage values. However, power systems normally use reactive power compensation at the receiving end or load center to increase the transfer of active power, improve voltage regulation, and reduce losses. The blue curve shows an increased margin with added reactive compensation, like capacitor banks, static vars compensators, or additional reactive local generation. Operators need to be careful on this condition, because maximum power transfer grows but the margin between the nominal voltage operation point and bifurcation point becomes much smaller. Voltage collapse may happen at voltages very close to nominal. Voltage stability indicators, PV curves, and reactive power (QV) curves may be used to determine margins, because voltage magnitude alone is not a clear indicator of proximity to the transfer limit.

In real-world complex power systems, one way to identify power transfer limits and define PV curves is using power flow simulation and plot voltage at the load center for different active power loads, keeping reactive power constant at the load. This process is normally automated in modern power flow simulators applying small variations of active power at one bus in the load center and plotting the voltage magnitude versus P at the load or through the transmission corridor. Power flow cases do not reach convergence beyond transfer limit, and the sensitivity of voltage changes versus power changes increases drastically very close to the limit, making it easy to identify the limit for the specific load flow case. However, each generation dispatch and load demand case will have a different curve and active transfer limits, because the reactive power and load sensitivity to voltage changes at the load center will be different for each new case. Fig. 5 shows the main variables affecting analysis and why finding transfer limit for a corridor is challenging.

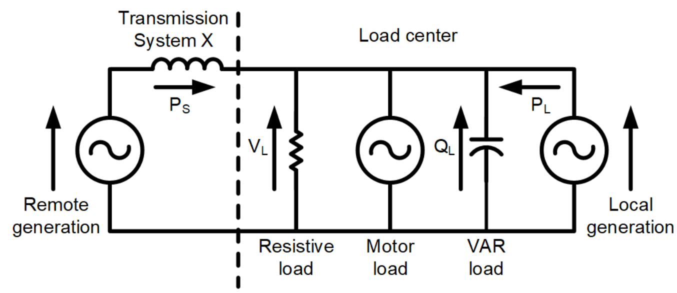

Fig. 5. Main load center variables that affect transfer limit.

Capacitor banks and static VAR compensators directly affect reactive power and power angle Θ in (3). The load model has an important effect, depending on how much constant impedance, constant power, or constant current is assumed during simulation. Accurate load models are difficult to validate on most real-world systems that serve multiple loads at regional or national level. Some commonly used simulation tools used for power system operation and planning purposes apply simplified general models that contribute to accuracy errors on the load flow results.

Local generation affects both reactive power and active power transfer.

B. *Dynamic Stability Analysis*

Dynamic stability studies also help to understand voltage stability after disturbance or contingencies. Several factors affect the accuracy of dynamic stability analysis and need to be considered. The main factors are generation voltage control, load models, low-voltage ride-through (LVRT) for inverter-based generation, and distribution voltage controls, like capacitor banks and load tap changers (LTC).

Generator excitation systems will try to regulate voltage and inject more reactive power during a disturbance on the network. Typical static excitation systems will respond very fast, increasing excitation voltage and current to increase generator terminal voltage into a 100 to 300 millisecond timeframe. The excitation current may temporarily exceed their permanent current capacity, but a secondary control loop will then reduce it to avoid thermal effects on the field produced by the overexcitation. This secondary loop control is known as the maximum or overexcitation limiter (OEL) and, depending on the control design and settings, may have response times from a few to several seconds. The OEL may limit the maximum reactive power below the original generator capability curve, as shown in Fig. 6.

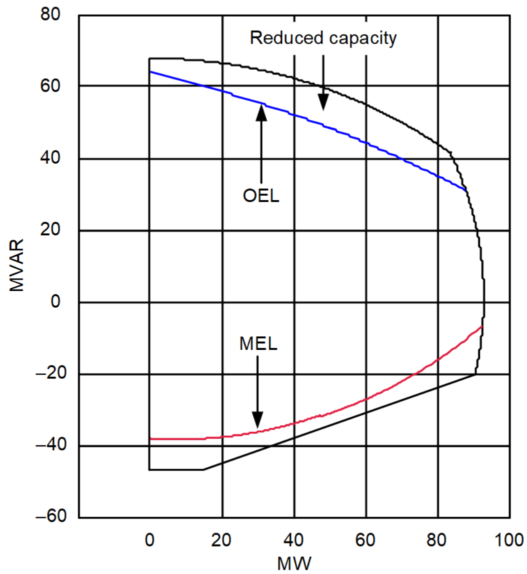

Fig. 6. Main load center variables that affect transfer limit.

The initial effect of voltage regulation models without a detailed model of OEL may lead to results looking like stable cases, while in reality, the OEL effect will lead to voltage collapse conditions after some seconds.

LTCs are also a critical factor. The LTC will act after some seconds to regulate the voltage at the load side after events with low-voltage effects. The voltage at load will increase, but reactive consumption will grow, reducing the margin to bifurcation point or leading to voltage collapse after some seconds.

The previous section mentions different types of load models and their effects on PV curves. The same concepts apply to dynamic analysis. Additionally, another effect known as fault-induced delayed voltage recovery (FIDVR) can also affect dynamic analysis results. Fig. 7 shows the comparison of a real-world fault event on a transmission line close to the Panama load center (recorded with phasor measurement units [PMUs] and a dynamic disturbance recorder) and simulation results using a simple load model for operation studies. Present regulatory operation manuals for Panama require modeling load as 30 percent of constant admittance and 70 percent of constant current, which is a very commonly used combination that provides good results for angular transient stability but may not lead to accurate results for voltage stability studies

Simulation results show that the voltage is depressed during the fault and that it recovers instantaneously after breakers clear the fault. However, records from the PMU show that the voltage recovered below 80 percent of nominal voltage and takes more than a second to recover to nominal levels.

Reference [3] explains in detail dynamic load modeling and FIDVR effects. The behavior of load will be affected by electronic loads and controls and different types of motors. Fig. 8 shows complex model components.

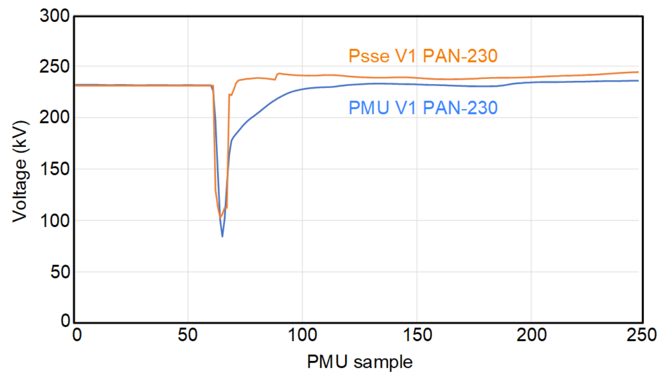

Fig. 7. FIDVR at a Panama load center, simulation versus measurement.

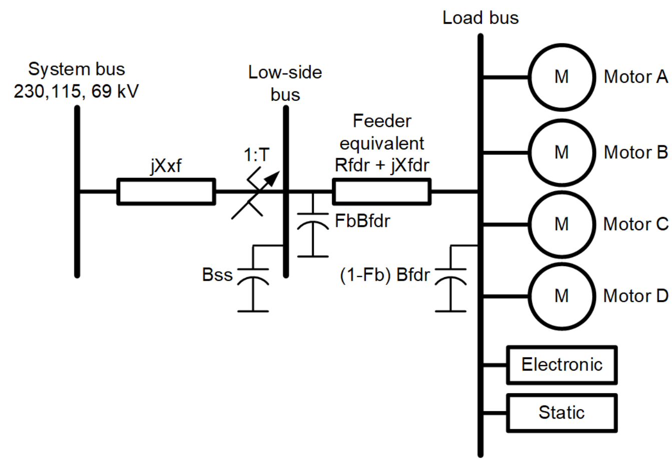

Fig. 8. Complex load model.

Some three-phase motor loads will be tripped or lost because the contactor will open fast if there is low voltage during times in the 20 to 100 ms order. Some of them may trip before breakers clear the fault or during the slow voltage recovery period. The worst effect came from single-phase induction motors, common in residential air-conditioning systems. These motors tend to stall if a low-voltage condition affects the phase where they are connected, increasing their reactive power consumption by factors of 4 or 5 times nominal. This reactive power consumption remains after the fault is cleared and voltage partially recovers, because the motors are already stalled. The motor protection takes a long time to trip because it normally consists of a thermomagnetic low-voltage breaker or other type of thermal protection. When there is a considerable amount of this type of load, the FIDVR effect has two consequences: reactive consumption can be very high, leading to a voltage collapse condition, and part of the load will be lost in an uncontrolled manner. This loss of load finally contributes to voltage recovery. Fig. 9 shows a simulation of reactive power demand at Panama City 230/115 kV transformers using the complex load model. This sudden change in reactive power may be used to differentiate events related only to voltage collapse caused by transmission limitations from events related to voltage effects produced by FIDVR.

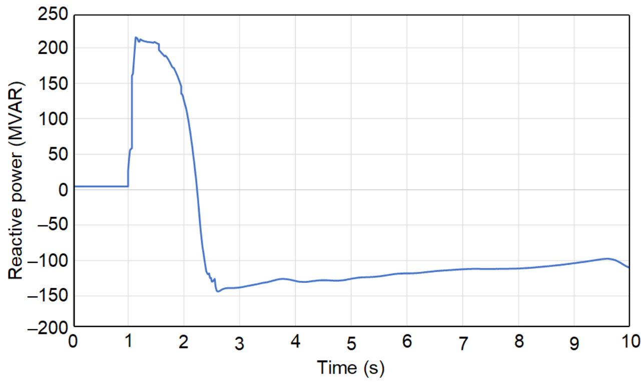

Fig. 9. Reactive power consumption at Panama load center during FIDVR using complex load model.

LVRT on generators is the ability of the generator to remain connected to the power system during low-voltage conditions. Dynamic models should consider the LVRT characteristics because, during low-voltage events, generators may trip, increasing the power transfer on the affected corridor and reducing the generator's reactive power contribution.

Proper modeling of OELs, LTCs, capacitor bank controls, LVRT characteristics, and load—especially complex motor load models—will have a major impact on dynamic voltage stability study results. For large regional systems and open markets with different participants, it is challenging to get accurate models for all these components, increasing the uncertainty about simulation results. However, PV curves and steady-state studies usually provide a conservative result, as they do not consider load reduction with voltage and generator initial transient results. For Panama's system protection scheme, PV curves are used as a main tool to establish limits and security margins, while dynamic results are used to validate conclusions and review specific cases.

III. Panama System Contingency Analysis Results

Transfer limits for the Panama transmission corridor from west to east were found using power flow simulation and PV curve analysis for different operation scenarios. An open market with several participants and large variations on generation cost and the availability of hydropower capacity in rain or dry seasons makes it very challenging to choose cases. Initially, 5 main season and dispatch scenarios were considered for 5 load levels (25 total scenarios). However, operation security assessments are done frequently for short- and medium-term operations with several more variations. PV curve sensitivity and transfer limit will provide different results, depending on the node selected on the load center for analysis and active power increments. Fig. 10 shows Panama's west-to-east transmission corridor, main load areas, main generation areas, and some buses, lines, and generators in the east that are relevant for analysis.

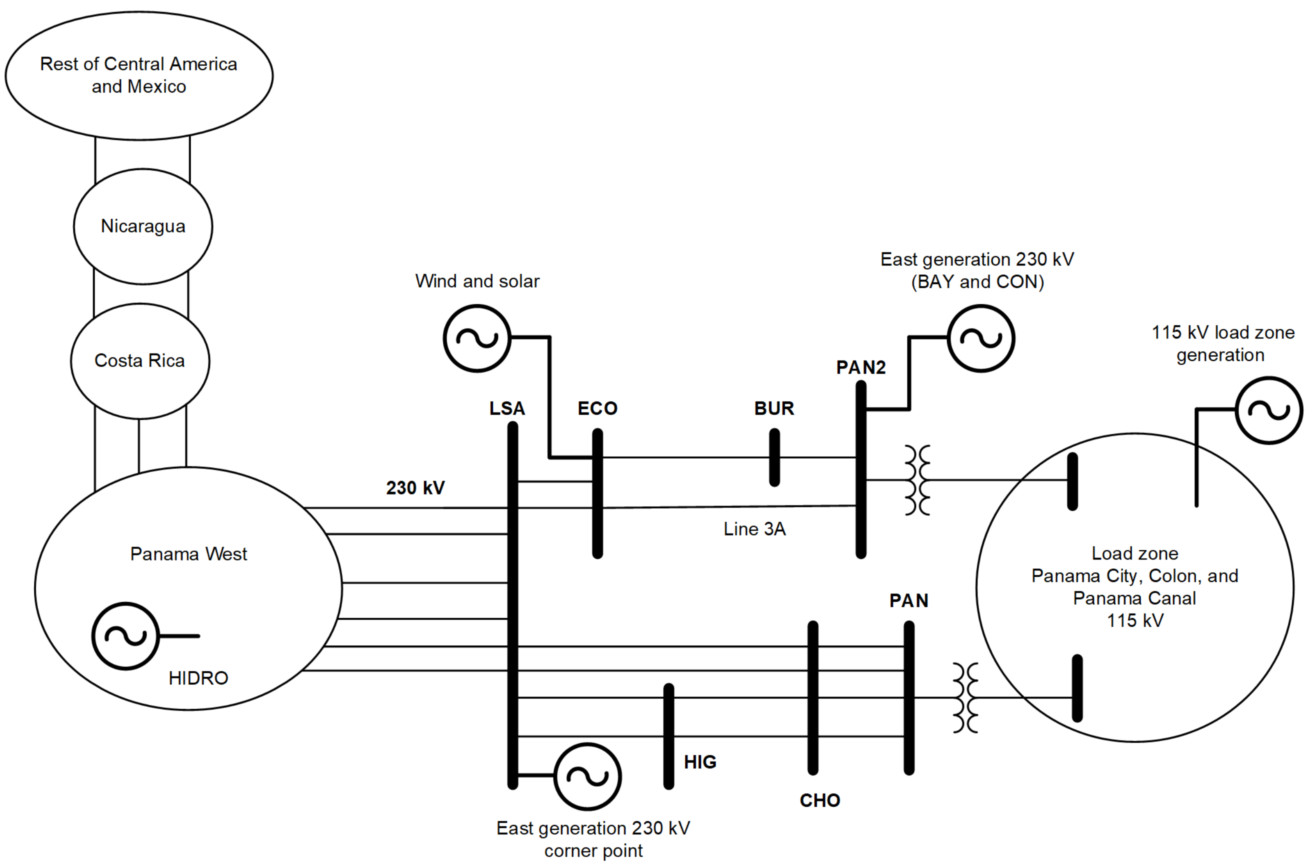

Fig. 10. Simplified Panama west-to-east transmission corridor and load and generation areas.

All of the load center area is connected from Panama (PAN) and Panama 2 (PAN2) substations through eight 230/115 kV transformers. PAN 115 kV bus was selected as the load or reference bus for PV curve analysis. The curves were traced, initially, versus load center total active power. However, other active power measurement points were evaluated to identify the most significant measure for system protection. Depending on the contingency, the power measurement can be different because a specific corridor is affected by the contingency or because the transfer limit after the contingency is more consistent between different operation scenarios. The power flow of lines connected to the Llano Sanchez substation (LSA) was used in the past to define west-to-east transfer limits because it is geographically located close to the center of the corridor and because all the power that flows from west to east crosses by this substation.

However, if we look at the transfer limit for contingency (N-1) of line 3A, El Coco (ECO) to PAN2, we will find a better measurement to define the transfer limit. The remedial action uses the total or added flow from the 6 lines (LSA – HIG) + (LSA – CHO) + (ECO – PAN2). There are several wind and solar parks connected to the ECO substation, and their power output has large changes between scenarios. Then, it makes sense to use the flow over these 6 lines instead of the total flow at LSA as the protection scheme measurement. The affected impedance and power transfer limit are from ECO to PAN, not from LSA to ECO. Fig. 11 shows PV curves for this contingency and one scenario. Loss of lines increases the total reactance and then reduces the limit, as shown in (3).

Steady-state quality criteria require that no line or transformer overloads and that all buses have a voltage between ±5 percent of nominal. The limit in this scenario, as established by economic dispatch and compliance with quality criteria, is 904 MW, with a transfer limit close to 940 MW. If the 3 A line was lost in these conditions, the system would suffer an immediate voltage collapse, because the power transfer is greater than the power transfer limit without this line, equal to 891 MW.

We observe that voltage collapse for this power transfer is 0.96 pu, above the allowed regulation limits under contingency. Voltage alone cannot be used as an indicator to take action. Undervoltage-based load-shedding schemes with delays typically applied in the order of several cycles or seconds (shown in [2]) are not effective for this problem, because actions would be triggered after the collapse is already in progress and load loss was uncontrolled.

There is no time to evaluate new power flow from the energy management system (EMS) state estimators, run new PV curves or voltage stability indices, and recover margin. Very fast action is desirable to shed load in a controlled manner before other loads trip in an uncontrolled manner, taking advantage of the transient response from the generator before OEL controls reduce excitation and before LTCs operate or inverter-based generators trip because voltage sag exceeded their LVRT characteristics. Load to shed must be enough to operate within the contingency transfer limits and with additional emergency security margins.

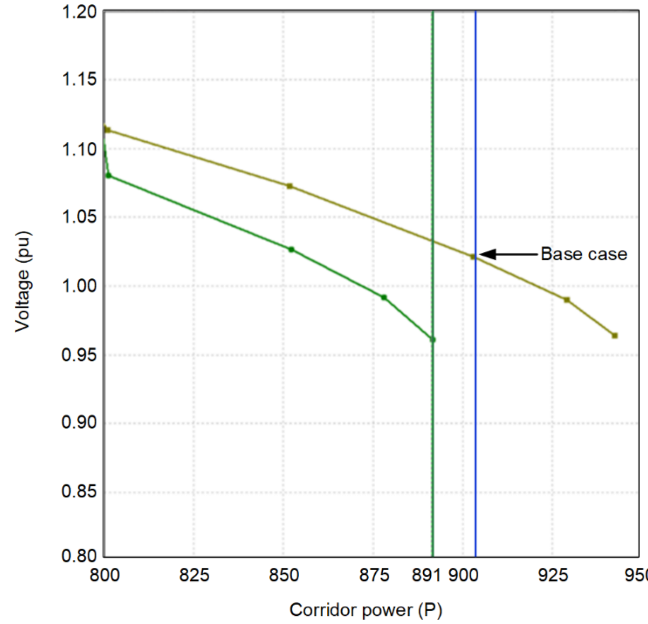

Fig. 11. PV curve for line 3 A contingency.

Another example is the generator contingencies on the east side of this system. Fig. 12 shows the PV curve for a base case contingency of one steam generator (156 MW) and the contingency of gas and steam generators together (230 MW). There is no change on the transmission corridor impedance, and the total active power transfer limit for the corridor does not change significantly. However, lost generation increases power transfer beyond the transfer limit for several scenarios. To better visualize the required load-shedding actions, PV curves for generation contingencies were plotted using the incremental power over the initial condition instead of the total corridor power.

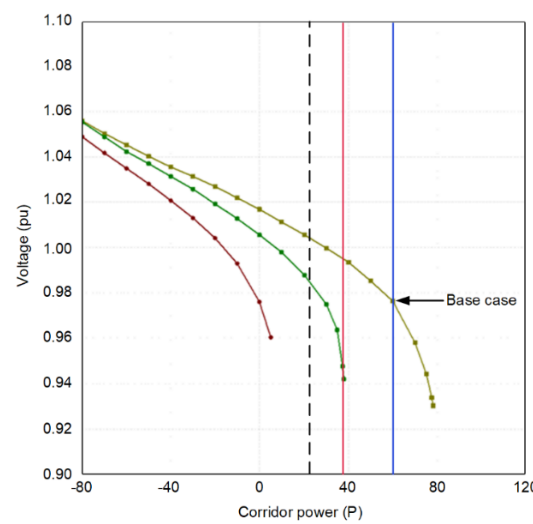

Fig. 12. PV curves for generator contingency on the east.

The blue line is the base case for this scenario. If only the steam generator at the plant in the east is lost, the system will experience immediate voltage collapse unless more than 20 MW are shed very fast. If the gas and steam generators are lost together, more than 60 MW must be shed. For each contingency, it is suggested to add a safety margin over the PV curve limit (at least 5 percent), as shown by the dotted line in Fig. 12 Consider the following factors:

1. Accuracy of power flow measurements. The equipment in the substation can have a typical error between 0.1 percent and 2 percent. Additionally, instrument transformers have a possible error ranging from 1–2 percent if the winding is for protection and 0.2–0.5 percent if the winding is for measuring.
2. Accuracy in power measurements at the loads to shed.
3. Load model uncertainty. In PV curve cases, we use a load model with fixed power; therefore, we did not consider additional margin, as using this method gives us the worst-case scenario. We made simulations using constant impedance, and the margin increased 3–4 percent, depending on the case, but we know there are several motors that behave as a constant current or constant power, and it is not possible to determine the exact mixture. Several FIDVR conditions have been observed, confirming the assumption of several motor loads. This type of load adds uncertainty to the simulation and the possibility of having worst cases because of the increased reactive power demand.
4. Network model uncertainty, mainly line impedances, in the order of 1 percent.
5. Uncertainty in inverter-based generation, LVRT, and protection models in the face of nearby faults that may lead to additional generation lost. An additional factor of 1 percent is assumed.
6. For cases that lead to voltage collapse, it is not recommended to act and leave the system very close to the PV curve limit because within a few minutes there are load changes, tap changes, actions of the excitation limiters, and other factors that could lead the system to a collapse condition.

There are some contingencies that do not lead to voltage collapse or nonconvergence cases. However, they result in a very low margin close to the transfer limit. System protection implementation also considers shedding load for these cases just to meet the required 5 percent criteria in the emergency state after one generation or line has been lost.

The amount of load to shed depends on the contingency, but there is a direct relationship between the total power transfer and the amount of load to shed to recover the 5 percent margin. The amount of load to shed is adaptive and proportional to the total power flow in the corridor, expressed as a percentage of the corridor power close to 5 percent. The next section explains the methodology to set the transfer limits and amount of load to shed.

The PV curves shown in Fig. 12 assume that generators are lost when they are operating at their maximum active power. However, generation may change over a wide range of conditions. The amount of load to shed varies, depending on the amount of generation lost, and it may not be required if generation is lost with low generator power output. The decision to trip a load becomes a two-variable problem. A nomogram methodology is proposed to set the arming conditions for the scheme. Nomograms are useful to analyze graphically complex problems that cannot be easily solved by detailed equations. Fig. 13 depicts a graph of a transmission corridor's total power on the X-axis and generation lost on the Y-axis. Several cases and PV curves were analyzed to obtain this graph. If the result is an unstable system or system below the minimum margin, it is marked with a triangle on the nomogram. If the case is stable, it is marked with a square. Once the total results are plotted, operation and restrain regions can be determined for the two variables and they can be used as arming conditions. For these particular cases, a simple straight line equation defines the operation and restrain regions.

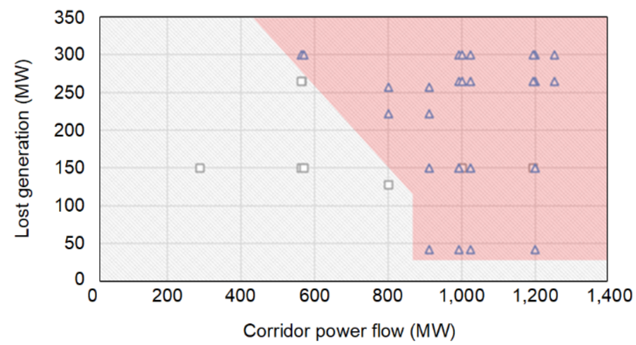

Fig. 13. Nomogram result for generator contingency.

IV. Fast Load-Shedding Implementation

A. *Load-Shedding Method*

The methodology to set the power transfer limits and the amount of load to shed is described in this section. The diversity of generation dispatch due to meteorological, economical, maintenance, and other conditions requires one to consider multiple scenarios (initially, five scenarios are considered). Additionally, each scenario considers five load demand cases of the Panama power system.

Table I shows an example for one contingency with only three scenarios and four load demand cases. A similar analysis is done for each contingency. For corridor power flows under 780 MW there are no margin violations; therefore, load-shedding actions are not necessary. The table shows that above 780 MW and below 1,050 MW, margin violations start to occur while the system is still stable; therefore, it is necessary to take load-shedding actions to recover margin of operation. For power flows above 1,050 MW, the system does not converge and load-shedding action is needed to recover system stability and the operation margin. At this point, only the power transfer limits are found. Next, it is necessary to determine the amount of load to shed.

A second part of the analysis must provide the factor that determines the amount of load to shed. From this analysis, we can observe that as the power transfer increases in the corridor, a contingency has more impact on the margin. For this reason, the factor is defined as a percentage of the total corridor power flow measured before the contingency. For the example, a first factor of 4 percent is proposed for corridor power flows above 760 MW and a factor of 7 percent is proposed for corridor power flows above 1,030 MW. Using these load-shedding factors, proportional to total corridor power flow, all the cases get a margin at least within the 5 percent required value.

It is important to note that the power transfer limits and the load-shedding factor values depend directly on the scenarios analyzed. A limited number of scenarios or conditions considerably reduces the reliability of the load-shedding factor. Considering a greater number of cases and diversity of scenarios results in a secure factor that covers all possible cases. However, considering many scenarios significantly increases the complexity and the time analysis. Additionally, some scenarios that are possible, but not very common, may lead to lower transfer limits and higher load-shedding factors than necessary for most operating conditions.

This proposed methodology allows the system to calculate the amount of load to shed online and before the contingency happens. The system is always calculating the amount of load to shed, but the detection of a particular contingency triggers the load-shedding actions. Using additional variables, such as total generation or reactive compensation at the load center, or determining PV curves and the power transfer limit in real time by taking data from the entire system operating conditions would lead to an even more adaptive system. However, it is challenging to implement for high-speed tripping. Research is in progress to determine the feasibility of this approach

B. Architecture and Infrastructure

Operating speed and dependability are critical aspects of the remedial action scheme (RAS) controller to ensure power system stability. The proposed RAS system architecture and technology guarantees very fast remediation operations. To achieve this dependability, the Panama RAS scheme is a dual primary system. A dual primary system is a redundant system in which two controllers (RAS-A and RAS-B) make decisions simultaneously. Each RAS controller collects information from the power system and performs calculations to decide if an action is necessary.

To make decisions based on specific contingencies, the RAS controllers receive measurements and status from equipment installed across the Panama power system in multiple substations. Equipment in remote substations report data at both slow and high speeds to the controllers using DNP3 and Generic Object-Oriented Substation Event (GOOSE) protocols. Additionally, synchrophasor data are collected from each equipment for monitoring proposes. All the equipment at substations communicate to RAS controllers using a Synchronous Digital Hierarchy (SDH) network over a fiber-optic backbone. The RAS controller also gets load data from two distribution companies through the ETESA supervisory control and data acquisition (SCADA) system to confirm the load per feeder in real time and optimize the load to shed.

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TABLE I
TRANSFER LIMITS AND AMOUNT TO SHED

	Scenario 1				**Scenario 2**				**Scenario 3**			
Load demand (MW)	1,100	1,300	1,500	1,700	1,100	1,300	1,500	1,700	1,100	1,300	1,500	1,700
Total power flow on corridor without contingency (MW)	601	701	720	780	660	850	950	970	791	950	1,050	1,130
Total power flow on corridor with contingency (MW)	606	708	728	788	670	861	962	980	799	958	*NC	*NC
Transfer limit with contingency (MW)	646	746	770	821	710	892	982	1,007	826	970	*NC	*NC
Distance to curve nose with contingency (%)	†6.7	†5.4	†5.8	‡4.3	†6.1	‡3.7	‡2.1	‡2.8	‡3.4	‡1.3	*NC	*NC
Shed load from 760 MW – 4%	-	-	-	31.2	-	34	38	38.8	31.6	38	-	-
Shed load from 1030 MW – 7%	-	-	-	-	-	-	-	-	-	-	73.5	79.1
Distance to curve nose with contingency and load-shedding action (%)	-	-	-	6.1	-	5.6	5.3	5.3	5.7	5.1	5.3	5.0

NC: System does not converge, need fast action. * Lowest corridor power with margin violation † Do not need recover margin. ‡ Need recover margin.

C. Load-Shedding Logic

The 230 kV voltage collapse scheme includes four line contingencies, and it should include power generation contingency schemes for each major power plant in the east. Implementing power generation contingency schemes is in progress and actually covers two generation plants. For each line contingency, the amount of load to shed is calculated using the logic shown in Fig. 14. Variables in Table II are operator-configurable values that the RAS controllers will receive from the human machine interface (HMI).

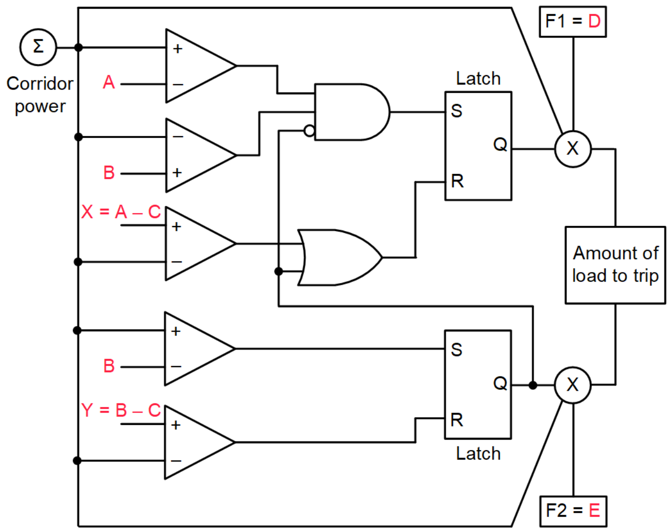

Fig. 14. Load-shedding calculation logic for 230 kV V_S voltage collapse scheme.

TABLE II
VARIABLE DEFINITION OF OPERATION LOGIC

Variable	Definition
A	Level 1 – Power flow (MW)
B	Level 2 – Power flow (MW)
C	Deadband (MW): to avoid chattering of arming condition
D	Load-Shedding Factor 1 (%)
E	Load-Shedding Factor 2 (%)
F	Dropout time (cycles)

The load-shedding algorithm of the RAS controllers is armed with the amount of load to trip when the corridor power flow exceeds the operator-defined Level 1 (Variable A). If the corridor power flow is greater than Level 1 and less than Level 2 (Variable B), then the RAS controllers determine that the corridor power flow is in Region 2, as shown in Fig. 15. During these operating conditions, the controllers multiply the corridor power flow value by the load-shedding Factor 1 (Variable D). However, if the corridor power flow exceeds Level 2, then the RAS controllers determine that the corridor power flow is in Region 3 and multiply the corridor power flow value by the load-shedding Factor 1 (Variable E). These multiplications determine the amount of load to shed as a percentage of total corridor power. If the corridor power is less than Level 1 minus the operator-defined deadband (Variable C), then the load-shedding algorithm is disarmed, and no amount of load to shed is calculated by the RAS controller.

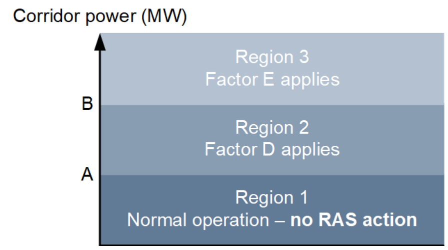

Fig. 15. Operating regions for 230 kV scheme.

Once the load-shedding algorithm is armed and the amount of load to shed is determined, the RAS controller waits for an appropriate contingency detection trigger signal before a trip signal is issued. The trigger signal for each voltage collapse contingency is the opening of the line that will result in voltage instability. This trigger is generated by the open-line detector (OLDA). Fig. 16 shows the trigger logic associated with this contingency. Power system studies show that the loss of any one of four lines leads to voltage instability in Panama because the real power flow transfer on the corridor exceeds PV curve stability margin. If an open-line condition is detected for a given contingency while the load-shedding algorithm is armed with an amount of load to shed, then the RAS controller issues a trip signal to trip the appropriate loads in the Panama system.

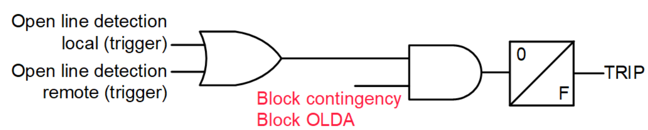

Fig. 16. Open-line detection logic from both line ends.

D. Load-Shedding Logic

Each contingency has an associated trigger and amount of load to shed. The loads are preselected for each contingency using information from distribution company SCADA system. This information allows optimal selection of loads to shed, selecting just the right amount of load to shed and avoiding the selection of loads that may not be enough if no real-time data are used. If SCADA information is not available for an individual load, several other loads are available for the scheme. If SCADA communications with loads fail to report all loads because distribution company SCADA was lost, a table considering conservative settings (or worst-case minimum loads) is used. Notice that the same load may be preselected for several contingencies. The controllers execute load-shedding logic every four milliseconds. This execution rate allows for a very quick and continuous calculation to update the load-shedding visualization screen and logic. This approach is known as "crosspoint switch," which relates contingencies with the corresponding loads to shed. See Fig. 17.

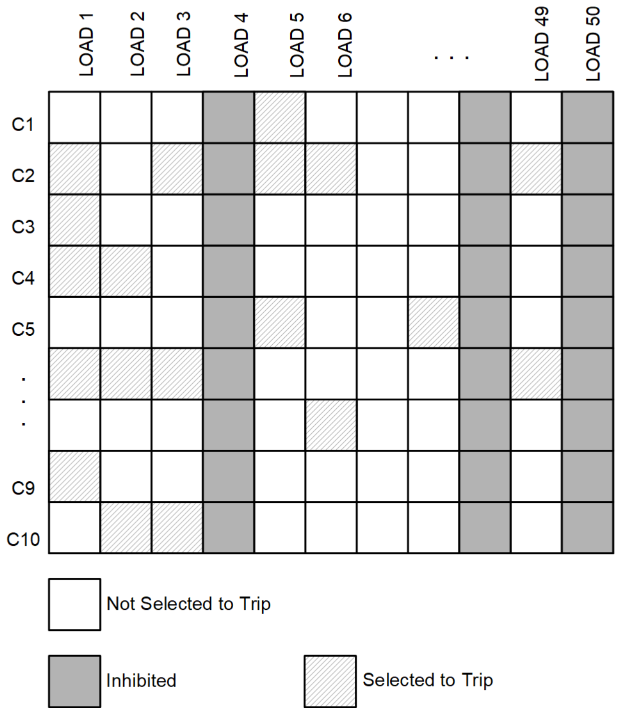

Fig. 17. Crosspoint screen, contingency versus load to shed.

V. System Validation and Field Results

A very important part of developing RASs is the system validation test. The designed and developed RAS system (controllers and all the equipment involved) must be tested before commissioning in the field. The validation is done using a real-time digital simulator. Real-time simulations allow external equipment to be connected to the simulation and exchange information between them; this is known as hardware-in-the-loop (HIL) tests. HIL tests consist of developing several real-time simulations on a reduced power system model of Panama. One contingency could be simulated multiple times under different scenarios and conditions to validate the correct response of the controller and the entire RAS system to each test.

Developing this kind of test makes it possible to find conditions that were not considered in the initial design, and it allows adjustment of them before the commissioning work. This also reduces the commissioning time on site due to most of the possible improvements being done in the lab. These findings could include mistakes in the system logic or end user network models. At the end of these validation tests, the result is an RAS system with high quality and a much easier field commissioning process.

VI. Conclusion

Implementation of a voltage collapse RAS scheme presented several challenges, including:

- Extensive simulation for different scenarios and power system conditions.
- Review of several previous events to learn from system performance.
- Proper modeling when possible and good criteria for assumptions where there is not enough data.
- Detailed engineering and interphases design coordinated between different stakeholders, like transmission, generation, and distribution companies; control centers; and those with different specialties, like protection, automation, and communication engineers.
- Use of reliable wide-area communications infrastructure.
- Periodic evaluation of topology and dispatch changes.
- Determining maintenance factors when settings or operation must be adapted during planned or unplanned maintenance of lines.

Solutions presented include load-shedding that adapts automatically to the power flow on the transmission corridor and generation; automated load selection logic; HMIs that allow visualization of load to shed; and other features. Schemes include several features to increase reliability, like redundancy, channel supervision, detection supervision, and others.

The project team is evaluating possible future improvements, such as developing an automated offline power system study methodology that allows faster analysis of future scenarios or maintenance cases. Another research area is the use of a reduced a power system model to incorporate real-time PV curve analysis into the RAS controller to automatically adapt the arming power flow conditions and load-shedding factors.

ETESA – CND get the following benefits after scheme implementation.

- Power transfer limit increase from the west to the load center on the east.
- Less operation cost using more hydropower from the west over thermal sources; fewer carbon emissions.
- Optimized operation of wind and solar resources connected to the ECO substation because the RAS scheme limit changed the transmission corridor reference point, depending on the contingency, allowing more power on this node.
- Improved system reliability, greatly reducing the possibility of system blackouts and increasing the security margin versus the PV curve limits, and less probability to develop slow voltage recovery issues.
- Optimized load-shedding because of the incorporation of distribution companies' information in real time.

VII. References

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VIII. Biographies

Alonso Castillo is the manager of technical support for the National Dispatch Center. He graduated from the Universidad Católica Santa María la Antigua as an electronic engineer, and he graduated from the Interamerican University of Panama with a master's in business administration with an emphasis in strategic management. He joined the Institute of Hydraulic Resources and Electrification in 1986 in the communications department in the area of microwave communications infrastructure and PABX voice service. Since 1989, Alonso has been part of the National Dispatch Center with assignments and responsibilities for hardware in supervisory control and data acquisition (SCADA). He works with hardware that structures and implements the wide-area monitoring system (WAMS) and quickly integrates it with SCADA, and he also works on power line carriers (PLCs) intercommunicating with fiber-optic multiplexed channels to form a supplementary protection scheme for the international interconnection. Alonso participates as a leader in implementing a special protection scheme (SPS) for the National Interconnected System of Panama: Special Protection System With Remedial Actions (SPEAR).

Rodrigo Palacios is the network studies analyst of the medium- and long-term planning section of the Centro Nacional de Despacho (CND) of Panama. He graduated from the Technological University of Panama where he obtained the title of electromechanical engineering in 2014. Within the CND, he began as an operator of the national network in real time. In 2017, he began his work in the medium- and long-term studies department, and he has experience in the development of steady-state studies, voltage stability, and dynamic and transitory analyses. With the SPEAR project, he was part of the personnel representing the operations management in the elaboration of the database and follow-up of the development of the consultancy, participating in the factory acceptance tests, and the onsite implementation tests.

Aaron Esparza is the project engineer in the special protection systems department for Schweitzer Engineering Laboratories (SEL) in Mexico. He received ME and PhD degrees in electrical engineering from Autonomous University of San Luis Potosí, San Luis Potosí, Mexico, in 2013 and 2018, respectively. His research interests are power system models and simulations, wide-area protection, and control applications.

Ulises Torres is the group manager in special protection systems for Schweitzer Engineering Laboratories (SEL) in Mexico. He graduated as an electrical engineer from the National Polytechnic Institute of Mexico in 2011, and is currently studying for a master's degree in electrical power systems at the Autonomous University of San Luis Potosí. In 2012, he joined SEL, where he has served as a factory acceptance test engineer, field service engineer, and power system studies engineer. He has led multiple protection and control projects. In 2016 he joined the area of special protection systems, participating in the creation, development, and implementation of multiple remedial action schemes. He has participated in the stability studies for the Panamanian electrical system (CND-ETESA) and lead the development and implementation of the remedial action scheme of Panama.

Jean León Eternod is the technology director for Schweitzer Engineering Laboratories (SEL) in Mexico. Prior to joining SEL in 1998, he worked for the Comisión Federal de Electricidad (CFE) power systems studies office in protection and control corporate management. While he was at CFE from 1991 to 1998, he worked with wide-area network protection schemes, single-pole trip and reclose studies, and database validation for short circuit, load flow, and dynamic simulation, including generator and control model validation for most CFE generators. He received his BSEE from the National Autonomous University of Mexico (UNAM), where he also completed postgraduate course work in power systems. He received training in power system simulation from Power Technologies, Inc. He has authored numerous technical papers on the topics of power system protection, simulation, and wide-area protection and control applications.

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