INTERCONNECT CHALLENGES IN THE DEVELOPING WORLD'S DISTRIBUTED GENERATION INFANCY

David C. Oehl, P.E.
President
MAVEN POWER

September 2006

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Overview

Significant challenges await the on-site or distributed power producer wanting to interconnect to a developing-world's national or regional government electric utility having little or no experience with the technical or operational considerations associated with interconnections. Due to recent economic growth and limitations on generation or transmission capacity, these utilities are now compelled to allow self-generation, albeit without extensive interconnect agreements or specifications applicable to distributed generation.

This manuscript profiles a case study of one of the first distributed generation applications in a given developing country—an onsite power plant in Colombia. In this case, the regional utility had little experience introducing an independent generator to the grid. There was not a formal interconnect agreement for on-site power applications. This manuscript details the technical and operational challenges encountered and how they were overcome to ensure the safety and availability of the grid, the on-site generation, and the end user's plant. The type of equipment used, operations sequences, relay protection schemes, and recloser issues are discussed. Controls used for plant load shedding, load following, utility power import control, and breaker operation are also discussed on an operational-level to allow the reader to follow the methods used.

The development of fast-track, personalized agreements were explored that allowed for the best tradeoff between safety, availability, and power quality. To reach satisfaction on both sides of the agreement, equipment additions and modifications were investigated. However, due to the minimal responsibilities required of the grid operator, greatly expedited solutions were proposed.

It is becoming ever more apparent that distributed generation is not solely reserved for developed countries with overheated economies. This manuscript describes some of the processes and techniques that have successfully been used to address the growing trend towards distributed generation in developing nations.

Project Background

Maven Power was contracted to provide power generation equipment and engineering services for a 2.5 MWe on-site, distributed generation power plant in Barranquilla, Colombia. With electrical power selling at around 11-13 cents/kWh and the price of natural gas at competitive levels, the spark gap (cost of fuel vs. cost of open market electricity) created an attractive scenario for on-site power. The plant was centered around two 1.33MWe natural gas fired reciprocating engines (see Figure 1). Maven Power was responsible for the electrical power equipment, balance of plant, and the design/integration engineering. Maven provided multiple 15kV switchgear sections, an ATS (automatic transfer switch) transfer trip control system, protection, metering, electrical coordination, power control, SCADA, and startup & commissioning services.

The power plant electrical configuration consisted of the two gas engines and their respective generator circuit breakers (G-1, G-2), a step up transformer to 13.2kV (T-1), generator feeder breaker (SG1), utility feeder breaker (SG2), and the ATS control which performed all sequencing, monitoring, and power transfer between sources. The single line diagram given in Figure 2 shows the setup.

Figure 1. 2.5MW On-site Power Plant

The plant was to be operated at base load, in parallel with the local utility (Electricaribe). On-site generation was at 480V, 60Hz and grid interconnection was done at 13.2kV. The end user had a relatively stable load og 2.5 - 3.0 MWe, such that the two gas engines could be operated at rated capacity with the additional power being imported from the utility. Power export from this facility was not permitted. The end user's facility was located in the industrial area of the city and connected to a general-use feeder. Downstream of the feeder, the end user's facility and some 70 other industrial customers were supplied through an OCR (overcurrent recloser) at 13.2kV.

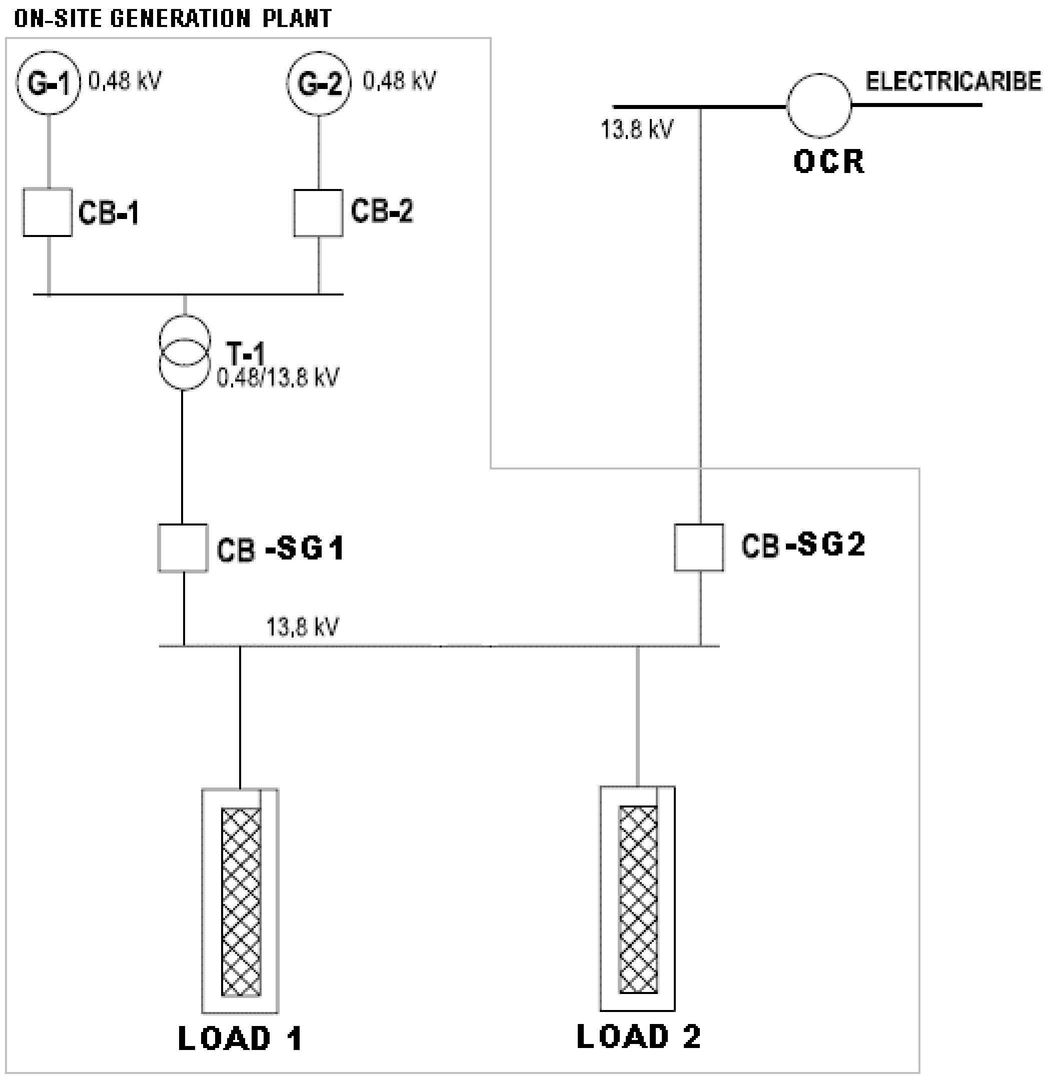

Figure 2. On-Site Generation Single Line Diagram

Power Plant Operation

The normal operating mode for the power plant was in grid parallel with the facility's load being supplied by both the on-site generators and power imported from Electricaribe. In the event of the loss of either source, the ATS control system would manage the transfer to the available source. The control system managed the operation of the 15kV generator feed switchgear (SG1) and the utility feed switchgear (SG2). The ATS performed an automatic transfer, which was accomplished using a semi-closed transition scheme. Under normal conditions, 400kW was supplied by the utility and 2000 kW by the generators. Upon loss of the normal (utility) source, the ATS was designed to activate a load-shedding scheme, trip the utility breaker and perform a closed transition to the generator supply. Just prior to the transition, the generators are toggled from base load (constant kW control) to load sharing mode (isochronous control). The purpose of the load-shedding scheme was to reduce the total plant load and allow the generators to carry the remaining load in an islanded operation. Upon restoration of the utility, the ATS performed an open transition to the utility, such that the utility carries the total plant load until the generators are re-synchronized. Once synchronized, the generators are brought on-line and set back to base load mode. The system then resumes normal operation. A detailed arrangement of the control system utilized is given below in Figure 3.

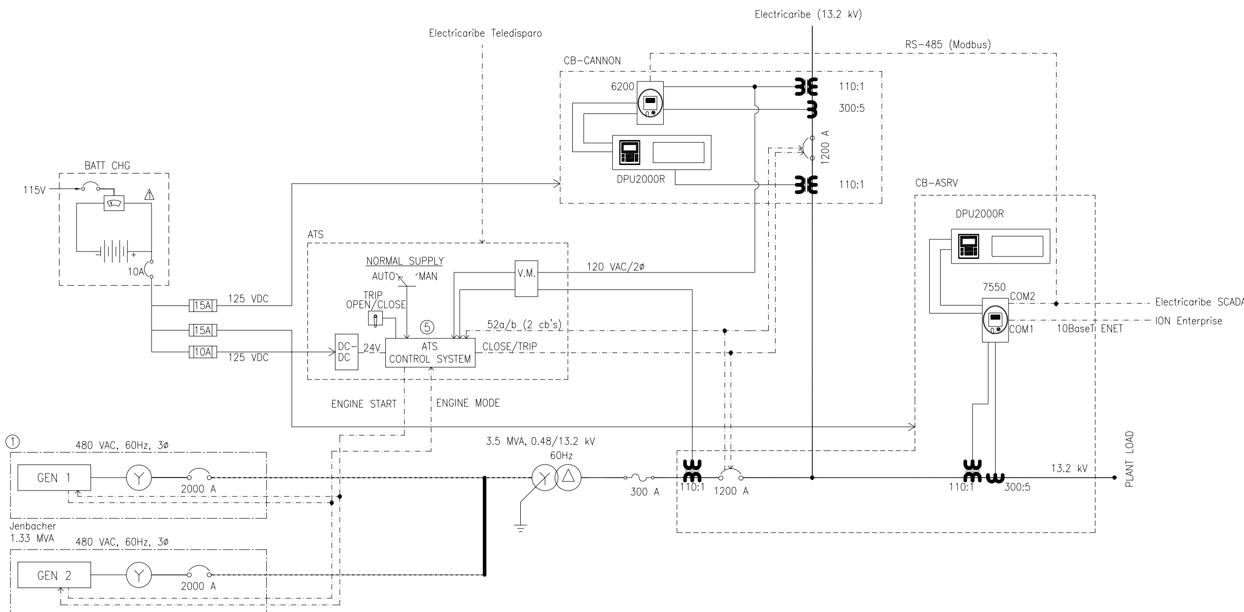

Figure 3. ATS Control, Metering & Protection Systems.

Challenges

Multiple challenges presented themselves throughout the course of this project. They included issues associated with grid instability, load shedding, load following, indeterminate recloser operation, and utility/regulatory body disputes.

Grid Instability

Upon completion of the power plant commissioning, within a few weeks it was observed that the local power grid, operated by Electricaribe, was significantly more unstable than anticipated or initially designed for based on the provided data. Power quality had degraded significantly since the time period represented by the data provided. The instability manifested itself in most cases as voltage sag, which was defined as a voltage level dropping more than 5% below nominal for more than 5 cycles. In many cases, the sags could be quite severe, with voltage levels dropping 15-20% of nominal for several cycles.

The lower intensity sags were caused by general disturbances grid-wide. This grid covered multiple regions of the country and served several major cities. The more severe sags were caused by the starting of large induction motors from one of the other consumers on the same feeder as the end user in this study. During one of these events, as the voltage dropped, the current and reactive power from all generating sources increased.

In many cases, the voltage sags resulted in a reverse power condition as monitored at the utility feeder entrance severe enough to trip the SG2 breaker (32R) and take the end user's facility and on-site generation off-line. Due to the high frequency of the voltage sag events (up to 6 times daily), the end user was negatively impacted due to the obvious effects on lost production and reduced revenue. An ABB DPU2000R protective relay had been installed in both SG1 and SG2 switchgear sections. Fault recorder data given in Table 1 demonstrates typical duration and current levels observed during a reverse power condition. Nominal phase current at rated load was approximately 130A.

SG2 Fault Recorder Data for Reverse Power (32R) Events				
Record No.	Date	Time	Duration (cycles)	Current (A)
1	21-Jan-06	5:34:07 AM	6.24	22
3	21-Jan-06	7:58:32 AM	3.46	40
5	21-Jan-06	10:12:55 AM	5.46	300
7	22-Jan-06	7:47:34 AM	6.21	45
12	22-Jan-06	9:23:37 PM	2.96	20
14	23-Jan-06	12:51:51 PM	6.21	45
16	24-Jan-06	4:34:39 AM	2.46	30
18	24-Jan-06	8:21:52 AM	2.96	15
		Average	4.50	cycles
		Max	6.24	cycles

Table 1. SG2 Reverse Power Condition Fault Recorder Data

It can be seen that the average voltage sag condition did not have a long duration—typically less than 5 cycles.

A typical reverse power condition vector diagram and waveform trace is shown in Figure 4. The condition is most apparent by the phase angle given between the phase voltage and phase current. In this example, V_c is referenced at the zero angle. The reverse power torque angle setting in the protective relay was 150˚ with a sector width of 180˚. Clearly the line phase current I_c is nearly at the maximum reverse power angle and both the 32R and 67P functions were triggered (green bars near the bottom center of the screen capture).

It is important to note that during each reverse power condition, no matter how limited, the SG2 breaker had to be tripped offline. This was required since there were no means available to distinguish whether the condition had been caused by a temporary, minor voltage sag or a complete loss of grid voltage due to an external fault.

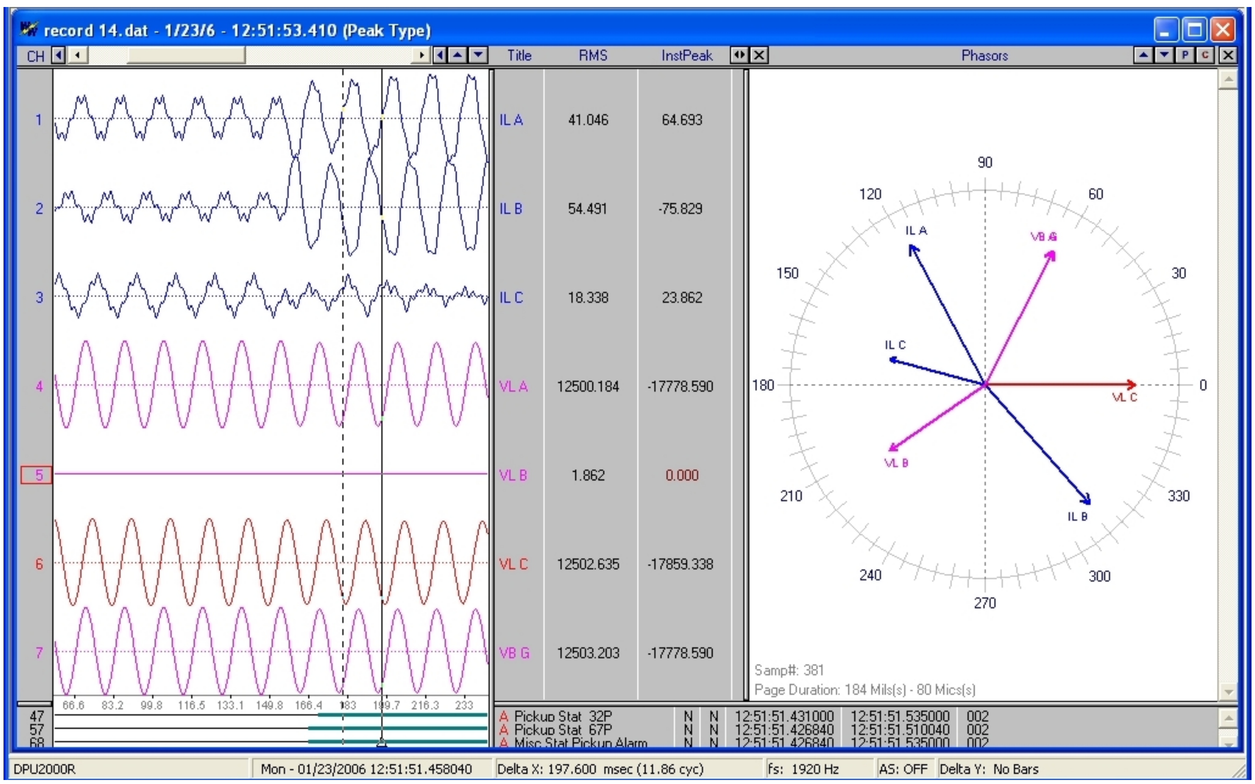

Figure 4. Typical Observed Reverse Power Condition

Load Shedding & Load Following

A load shedding system was investigated such that, upon loss of the utility or other (32R) tripping of the SG2 breaker, the end user’s facility could remain online—powered by the onsite generators. However, loads available for shedding, two 500hp motor-driven compressors, were so large that shedding them would have interrupted the facility operation entirely. It was not feasible to trip the compressors offline. Shedding of smaller loads, while possible, was not sufficient to reduce the load below the base load rating of the generators. This would have caused the generators to trip offline due to an overload condition. It was concluded that an effective load shedding scheme could not be implemented under the given conditions.

A load following scheme, however, was implemented that was designed to minimize the effect of the grid's voltage sags on the end user's plant. It was observed that if a constant minimum amount of import power was maintained (approximately 150kW) during parallel operation, the instabilities on the grid had less effect on the on-site power generation, and reverse power tripping was reduced. During the voltage sags, less real and reactive power was pulled out to the grid from the on-site generators. The ATS control continuously metered utility import power as well as the on-site generation power. Since the generators were normally deployed in a base load, or kW control mode, they could not self-regulate based on the changing plant load at the facility. The kW variation, or swing as it is often termed, was carried by the utility. However, during times of low facility load, such as typically occurred on weekends, the amount of imported load could fall well below the 150kW threshold required to minimize 32R tripping during voltage sags. The load following control monitored both generator and utility load. During times of low load, a signal was sent from the ATS site controller to the generator controls in order to lower the kW control setpoint on the individual units. This allowed for a constant import level of 150kW, and reduced reverse power tripping for all but the more severe voltage sag conditions. In effect, during low plant load conditions, the generators became the variable, or swing source.

Recloser Issues

Further complicating matters, the utility source coming into the customer's plant was fed from an overcurrent recloser (OCR). Due to the novelty of on-site and distributed generation in this part of the country, the local utility was not prepared to effectively address recloser operation as required in an on-site or distributed generation scenario. The recloser was configured and designed around a single source of generation and was set to clear the feeder (trip) in the event of a fault and to automatically re-close 500mS later. This was cause for great concern as the recloser would operate regardless of the presence of another generation source on its downstream line, without any attempt to synchronize the two existing sources. This could result in serious equipment damage, or injury and death to support personnel. The inability to lockout the recloser after it tripped to prevent a reclose operation into the live, onsite generation, posed the largest challenge to the ability to provide uninterrupted power to the end user. Since it was impossible to distinguish a 32R reverse power condition as being caused by the OCR tripping offline or a simple grid voltage sag, the on-site generation plant had to be tripped offline in every instance of detected reverse power—causing the end user's facility to undergo an open transition to the utility source and resulting in a momentary interruption. While not of great inconvenience to the facility, the high frequency of voltage sags and full load SG2 trips did cause significant concern for the health and integrity of the generators and their accompanying switchgear.

Utility/Regulatory Body Issues

Two solutions to the problem were proposed by Maven Power to the local utility representatives. The first was an operational procedure. As part of the original scope of work, Maven Power performed the integration of a SCADA (Supervisory Control and Data Acquisition) system which provided for remote monitoring and control of the on-site power generation by the local utility. Power parameters such as kW, kVAR, kVA, Hz, and power factor were provided allowing Electricaribe the ability to monitor the remote generation facility. Also included in the SCADA system was the ability to remotely trip the SG2 utility feeder breaker and to provide feedback information on the breaker position. The proposed solution required Electricaribe to transmit a trip signal to SG2 any time a fault occurred on the OCR feeder, and to not allow the OCR to re-close until the breaker position indication was that of an open SG2 breaker (successful SG2 trip command). This procedure was designed to prevent both an islanded condition as well as a re-close into a live buss. This solution was problematic in that the remote trip signal was transmitted using fiber optic cable over a distance of several miles. While the communications protocol and the media were robust, the customer's transmitting and receiving RTU equipment was prone to interference and temporary communications interruptions occurred on a frequent basis. In the event communications were down at any point during the recloser period (500mS), the inability of the utility to block the recloser operation would place the system in great peril.

The second solution was to implement a synch check (25) or undervoltage (27) monitoring system at the utility's substation where the OCR was located. This system would monitor the line and load side of the OCR for a voltage source. Following an OCR trip, and in the absence of a source on the load side, a re-close operation would be permitted. If both line and load sources were present (islanded condition on the load side), a re-close operation would be prevented. For multiple phase monitoring, these solutions required the installation of a minimum of two (2) 15kV PTs in the case of the undervoltage monitoring, and four (4) PTs in the case of a synchronization check.

Both proposed solutions were initially rejected. The first solution was rejected outright with the utility asserting that with the communication system's unreliability, this could result in lengthy time periods in order to verify the successful tripping of the SG2 which isolated the plant. This would have an adverse impact on the other numerous power consumers connected to the common general use feeder. The second proposal was countered with a variation on how the reverse power relaying was to be performed. The original reverse power function used was 32R, or an instantaneous reverse power. This had the effect of tripping the SG2 breaker without regard to the intensity or duration of the reverse power condition. Electricaribe suggested that the 67P function be used instead—directional-phase time-overcurrent. Maven Power had indeed analyzed the appropriateness of this function early in the design phase of the project. This function could be set to allow a given intensity and duration of reverse power to flow before tripping the SG2 breaker. The basic principle is that the 67P curve settings (pickup & time dial) are such that some reverse current is permitted which allows SG2 to remain online and both sources in parallel during the voltage sag transients observed on the grid, but only for a duration less than that of the OCR's re-close time setting. If the observed reverse power condition were caused by a recloser trip instead of a voltage sag, this would ensure SG2 tripped offline before the re-close operation occurred. A sample of the timing scheme is given in Figure 5:

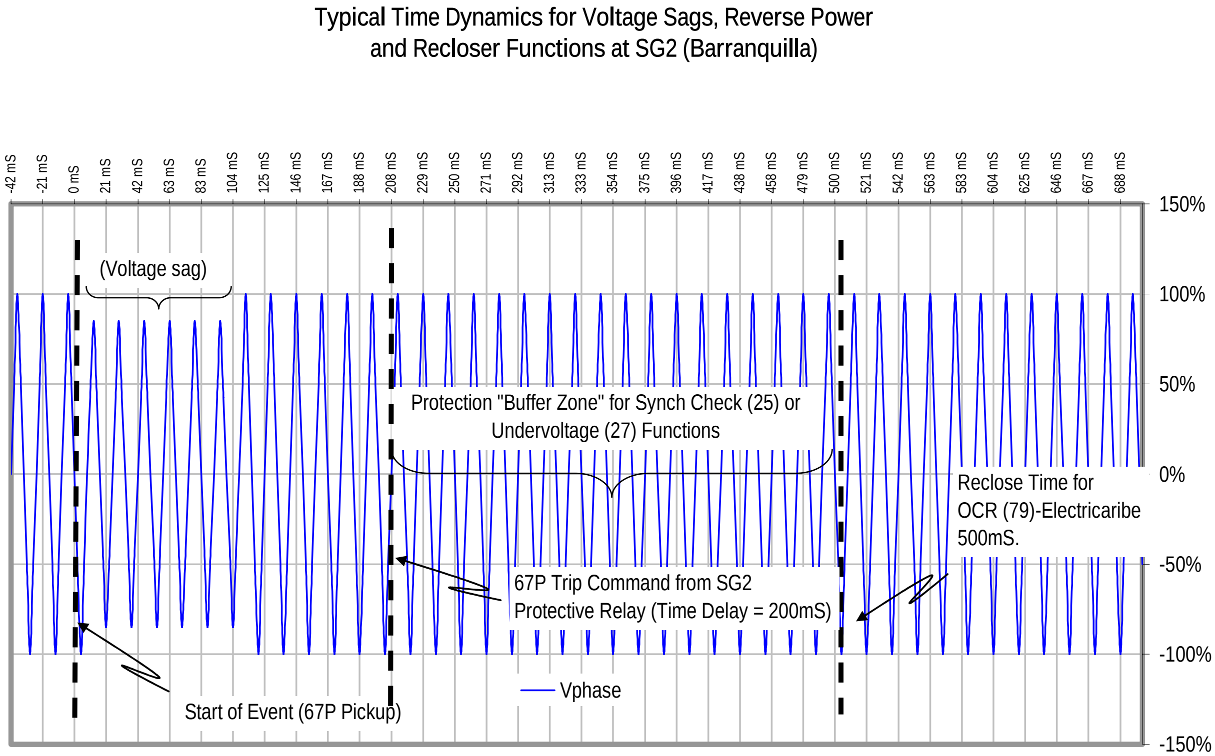

Figure 5. Recloser & Reverse Power Timing.

Maven rejected the idea of the sole use of the 67P function without a 25 or 27 function on the OCR. For such a critical application, it was not deemed prudent to rely solely on a timing scheme and the integrity of one OCR control which was beyond Maven's operational or technical control.

At present, negotiations are ongoing to implement the synch check or undervoltage monitoring systems in the utility's recloser.

Conclusion

On-site power and distributed generation must balance the needs of the end user, the power generator, and the local grid. In a market new to distributed generation, regulatory bodies and utilities may not be prepared or empowered to expeditiously make system modifications to accommodate new power plants. Available tools such as protective relaying, system coordination, load shedding, load following, an understanding of system dynamics, and integration between all parties involved can lead to a safe and beneficial distributed generation solution in a rapidly growing, developing country.