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Project Abeyta 1,500 KW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2008-01)

March 2009

Prepared by:

Public Service Company of New Mexico

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts.

Any correspondence concerning this document, including technical and commercial questions should be referred to:

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EXECUTIVE SUMMARY

The XXXXX submitted a "Small Generator Interconnection Request" for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 1,500 KW AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Abeyta and would be connected to Gallinas Feeder 11. An application was submitted based on the 'Open Access Transmission Tariff of Public Service Company of New Mexico', Attachment J 'Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW'.

The estimated cost of connecting Project Abeyta to the distribution primary is:

	ESTIMATED COSTS 2009$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ XXX	8 months
Interconnection**	$ XXX	8 months
PNM metering	$ XXX	8 months
Communication	$ XXX	8 months
Protection	$ XXX	8 months
TOTAL	**$ XXX**	

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Abeyta does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gallinas Feeder 11 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud will not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not adversely impact the protection coordination on Gallinas Feeder 11.
7. Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Abeyta and has determined that there are no adverse impacts associated with a 1,500 KW AC source connected to Gallinas Feeder 11.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gallinas Feeder 11 is maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Abeyta. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Abeyta proposes to connect a 1,500 KW AC PV facility to Gallinas Substation Feeder 11 in Las Vegas, NM. The Project will be located southwest of New Mexico Ave and Tecolote St as shown in Figure 1. The circuit distance from Gallinas Substation to the Project Abeyta point of interconnection (POI) on the existing distribution system is about 34,392 ft. or 6.5 miles.

Figure 1 ***– Project Abeyta Location***

3.0 SYSTEM CONFIGURATION

Project Abeyta is connected to Gallinas Feeder 11 served from Gallinas Substation. Table 1 shows the rating of Gallinas Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Gallinas	22.4	22.61	24.95	115-12.47

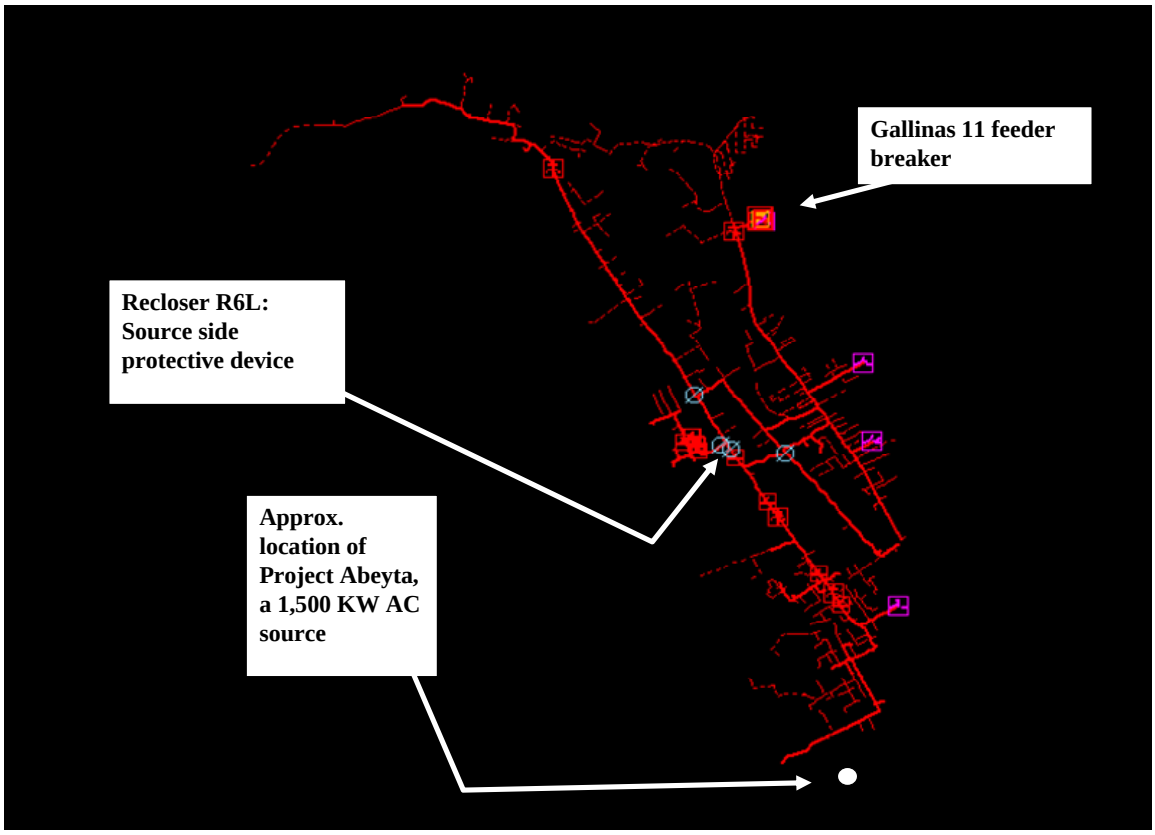
Table 2 shows the non-coincident peak 2008 peak summer loads for Gallinas Substation and feeders.

***Table 2* - July 2008 Non-coincident Peak Loads**

Feeder	July 2008 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Gallinas				
Gallinas 11	4,830	-824	4,900	-98.6
Gallinas 12	4,746	469	4,769	99.5
Gallinas 13	0	0	0	
Gallinas 14	0	0	0	
Gallinas Sub	9,560	947	9,607	99.5

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

Figure 2 *– Synergee model of Gallinas Feeder 11*



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Gallinas Feeder 11 are shown in Table 3:

Table 3 ***- Gallinas Feeder 11 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Dec 16, 2008	6 PM	6,979	461	6,994	99.8	327	321	312
Aug 17, 2008	7 AM	2,530	-965	2,708	-93.4	126	119	124

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

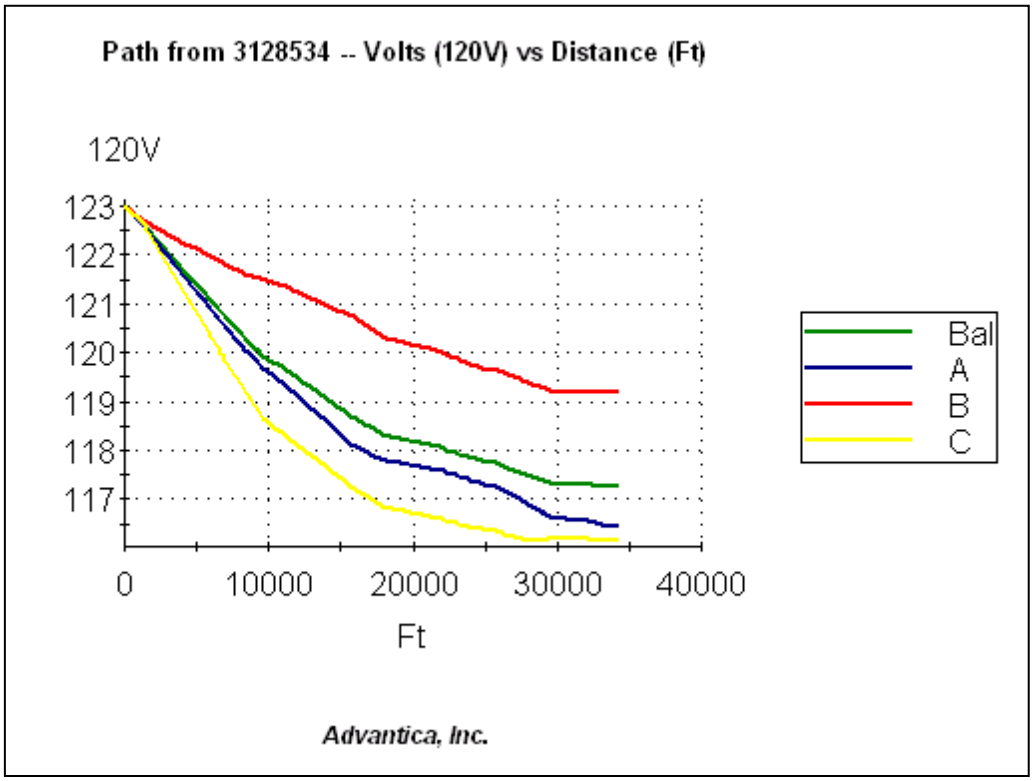
4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. No transmission voltage issues are anticipated associated with Project Abeyta at maximum output.

4.2 Voltage impacts for maximum daylight hours load

The Gallinas Feeder 11 voltage for the feeder maximum daylight hours load for 2008 with and without Project Abeyta, per the Synergee model, are shown in Graphs 1 and 2.

Graph 1 - Gallinas Feeder 11 voltage drop from Gallinas Substation to the POI without Project Abeyta for daylight hours maximum load on December 16, 2008

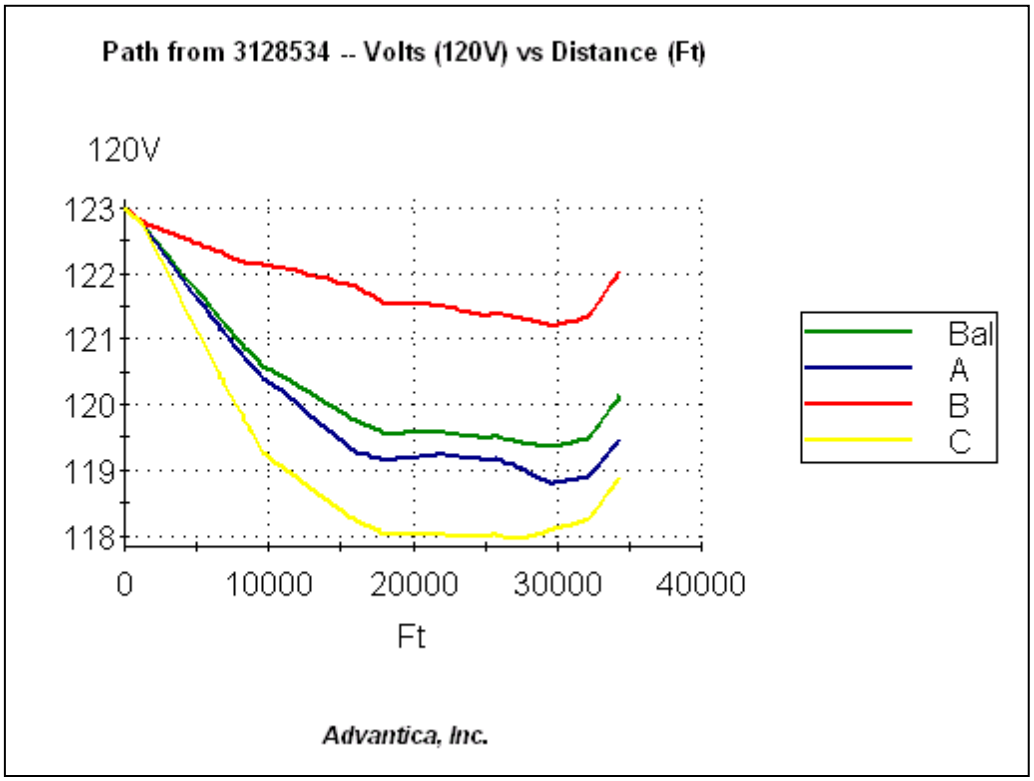


The model voltages at the point of interconnection are:

Phase A – 116.5 volts Phase B – 119.2 volts Phase C – 116.2 volts Balanced – 117.3 volts

The voltages on Gallinas Feeder 11 prior to the installation of Project Abeyta are within PNM voltage criteria (ANSI C84.1) Range B limits at the POI and are acceptable.

Graph 2 - Gallinas Feeder 11 voltage drop from Gallinas Substation to the POI with Project Abeyta for daylight hours maximum load on December 16, 2008



The model voltages at the point of interconnection are:

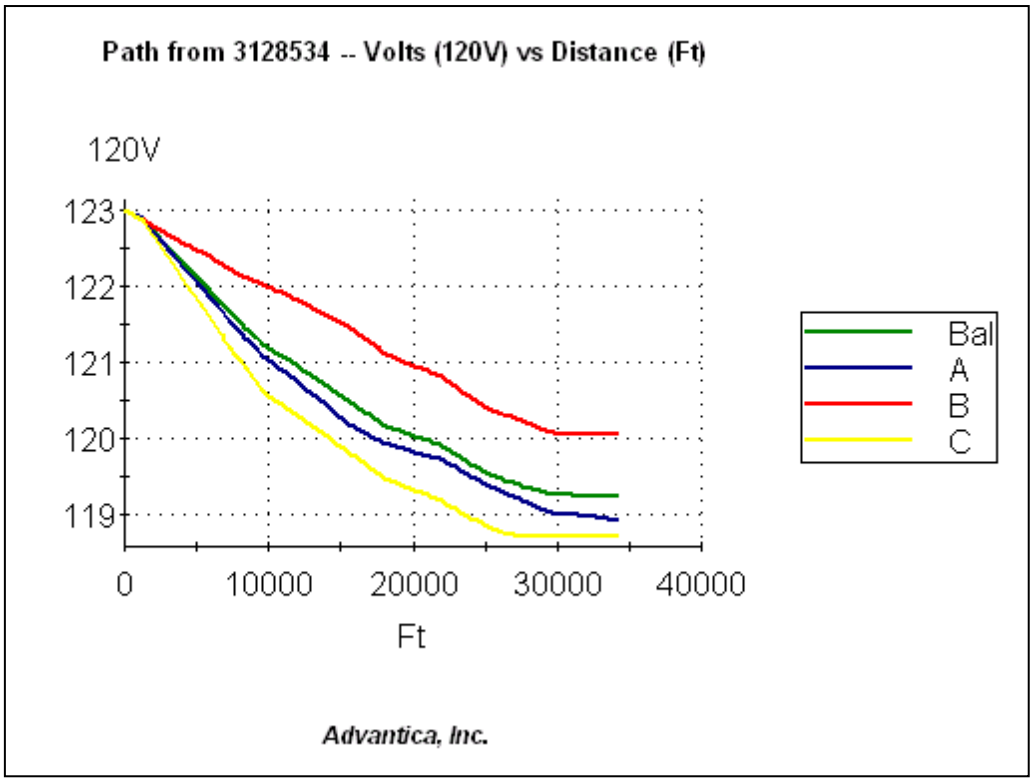
Phase A – 119.6 volts Phase B – 122.1 volts Phase C – 119.0 volts Balanced – 120.2 volts

The voltages on Gallinas Feeder 11 after the installation of Project Abeyta are within the PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable.

4.3 Voltage impacts for minimum daylight hours load

The Gallinas Feeder 11 voltage for the feeder minimum daylight hours load for 2008 with and without Project Abeyta, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 - Gallinas Feeder 11 voltage drop from Gallinas Substation to the POI without Project Abeyta for daylight hours minimum load on August 17, 2008

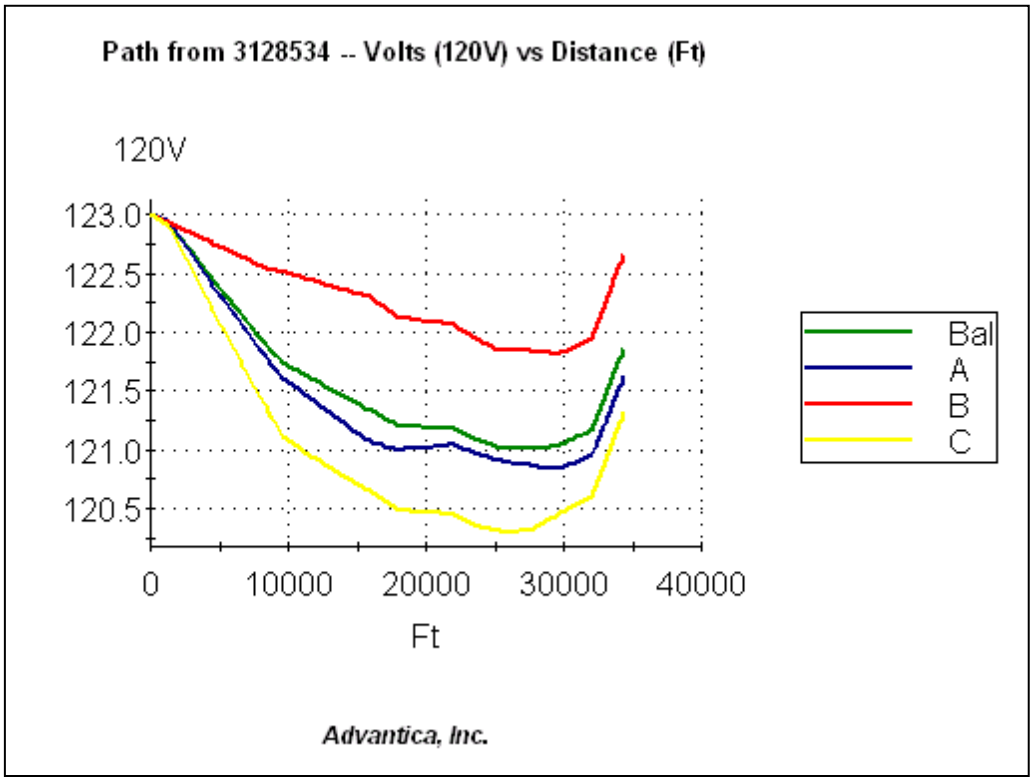


The model voltages at the point of interconnection are:

Phase A – 118.9 volts Phase B – 120.1 volts Phase C – 118.7 volts Balanced – 119.2 volts

The voltages on Gallinas Feeder 11 prior to the installation of Project Abeyta are within the PNM voltage criteria (ANSI C84.1) Range A at the POI and are acceptable. The minimum load was modeled with one of the two 1,200 KVAR capacitor banks on Gallinas Feeder 11 de-energized.

Graph 4 – Gallinas Feeder 11 voltage drop from Gallinas Substation to the POI with Project Abeyta for daylight hours minimum load on August 17, 2008



The model voltages at the point of interconnection are:

Phase A – 121.6 volts Phase B – 122.7 volts Phase C – 121.3 volts Balanced – 121.9 volts

The voltages on Gallinas Feeder 11 after the installation of Project Abeyta are within the PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable. The minimum load was modeled with one of the two 1,200 KVAR capacitor banks on Gallinas Feeder 11 de-energized.

In conclusion, Project Abeyta output does cause the voltage on Gallinas Feeder 11 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Gallinas Feeder 11 does not have a voltage regulator installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 1,500 KW source on the feeder would be less than 0.1 volts for high or low load periods. This voltage variance will be insufficient to cause the substation LTC to operate for high or low load on the feeder.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Abeyta POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

Table 4 ***- Voltage flicker on Gallinas Feeder 11 due to Project Abeyta***

	POI Voltage Gallinas Feeder 11 Loading	
	Minimum	**Maximum**
Without Project	119.2	117.3
With Project	121.9	120.2
% Voltage Flicker	**2.27**	**2.47**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 5 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
2.27	1/hour	30/minute
2.47	1/hour	20/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 4 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 5. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Abeyta POI to the substation were reviewed using the Synergee feeder model with and without Project Abeyta maximum output of 1,500 KW AC.

There were no conductor loading problems from the POI to the substation on Gallinas Feeder 11 with and without Project Abeyta during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Gallinas Feeder 11 has two 1,200 KVAR RCCS controlled capacitor banks. The July 2008 peak load on the feeder was 4,830 KW - j 824 KVAR or 4,900 KVA at a 98.6% leading power factor. The switched capacitor banks were energized. Project Abeyta at a 1,500 KW AC output would change the apparent feeder loading to 3,330 KW - j 824 KVAR or 3,430 KVA at a 97.1% leading power factor. This power factor value is outside of the RCCS power factor control point. The RCCS program may adjust the feeder power factor and a 1,200 KVAR capacitor would be de-energized by the RCCS program.

Project Abeyta may cause a 1,200 KVAR capacitor to be de-energized by the RCCS program for Gallinas Feeder 11, but no voltage issues were identified and the resulting new power factor would be acceptable.

9.0 PROTECTION

Gallinas Substation Feeder 11 is protected by a 1,200 amp circuit breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclosing relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, CA differential relays that trip a lockout relay to open the switchgear main breaker and 115kV circuit switcher. Approximately 3.52 miles from the substation, there is a Nova recloser with Form 6 controller. Project Abeyta will be connected to the system approximately 6.5 miles from the substation and 3.01 miles from the recloser on the load side.

Fault analysis of the system was conducted to determine the impact of Project Abeyta connection on the feeder protective devices. The Project was modeled in Synergee to produce the 208 amps of fault current on the 12.47 kV distribution system as noted in the interconnection application.

The first protective device considered was the impact to the Nova recloser with Form 6 controller. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of Project Abeyta fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of Project Abeyta. Finally, the feeder circuit breaker relay coordination was reviewed. Fault current contributions from Project Abeyta do not create any feeder circuit breaker protection mis-coordination issues on the feeder.

Project Abeyta contribution to fault current does not adversely impact the protection coordination on Gallinas Feeder 11. Thus, no system protection improvements are needed on Gallinas Feeder 11.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Abeyta output never exceeds the minimum load on Gallinas Feeder 11 during daylight hours. Therefore, Project Abeyta never causes a flow of power into Gallinas Substation. No Gallinas Feeder 11 equipment overloads were identified.

11.0 METERING and COMMUNICATION

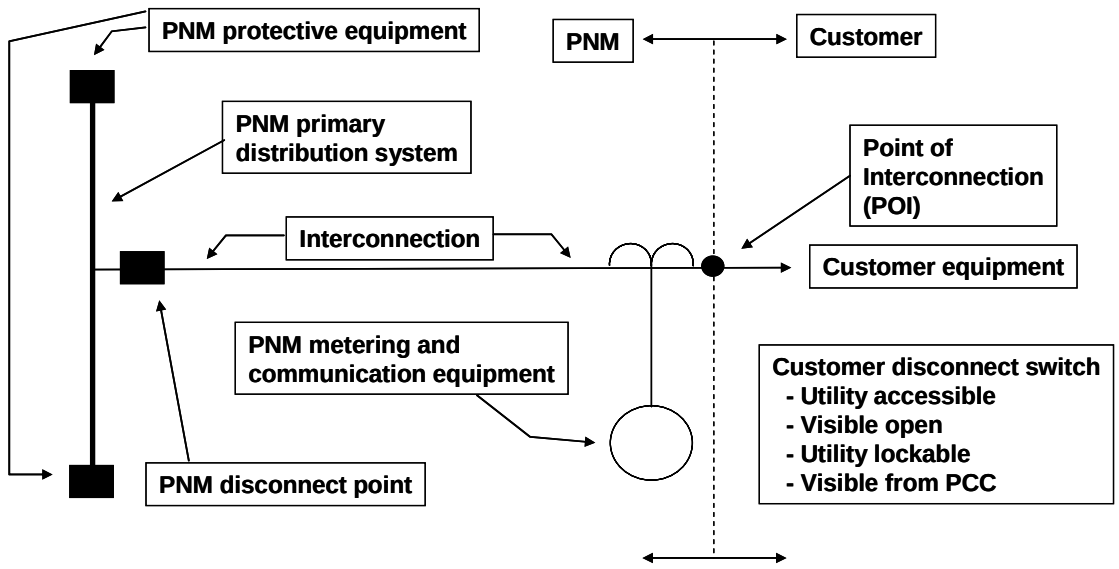
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 6.

Table 6 ***- Project Abeyta Interconnection Cost***

	ESTIMATED COSTS 2009$
PNM disconnect point*	$ XXX
Interconnection**	$ XXX
PNM metering	$ XXX
Communication	$ XXX
Protection	$ XXX
TOTAL	**$ XXX**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Abeyta does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gallinas Feeder 11. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Remotely controlled capacitor banks on the feeder may be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductors ratings to be exceeded. Finally, analysis shows that Project Abeyta output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Abeyta and has determined that there are no adverse impacts associated with a 1,500 KW AC source connected to Gallinas Feeder 11.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gallinas Feeder 11 is maintained within established PNM voltage, equipment and fault protection criteria.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binging agreements to interconnect.

XXXXX

Project Arriba 5,000 KW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2008-03)

March 2009

Prepared by:

Public Service Company of New Mexico

Electric Services
Transmission Operations

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This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts.

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List of Figures and Tables

EXECUTIVE SUMMARY

The XXXXX submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 5,000 KW AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Arriba and would be connected to Arriba Feeder 12. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Attachment J Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW.

The estimated cost of connecting Project Arriba to the distribution primary is:

	ESTIMATED COSTS 2009$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ XXX	
Interconnection**	$ XXX	8 months
PNM metering	$ XXX	8 months
Communication	$ XXX	8 months
Protection***	$ XXX	8 months
TOTAL	**$ XXX**	

* PNM disconnect point is an existing substation feeder breaker.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Arriba does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Arriba Feeder 12 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but did not have an adverse effect.
3. Project output variations due to clouds were found to not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. There are no remotely controlled capacitor banks on the feeder.
6. The Project contribution to fault current requires the Arriba Substation protection scheme be modified to isolate the Project in the event of a substation bus fault.
7. Project output will cause a flow of electricity from the distribution system through the substation transformer, but this does not cause an adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Arriba and has determined that there are no adverse impacts associated with a 5,000 KW AC source connected to Arriba Substation with a dedicated distribution primary source of Arriba Feeder 12.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Arriba Substation is maintained within established PNM voltage, equipment and fault protection criteria.

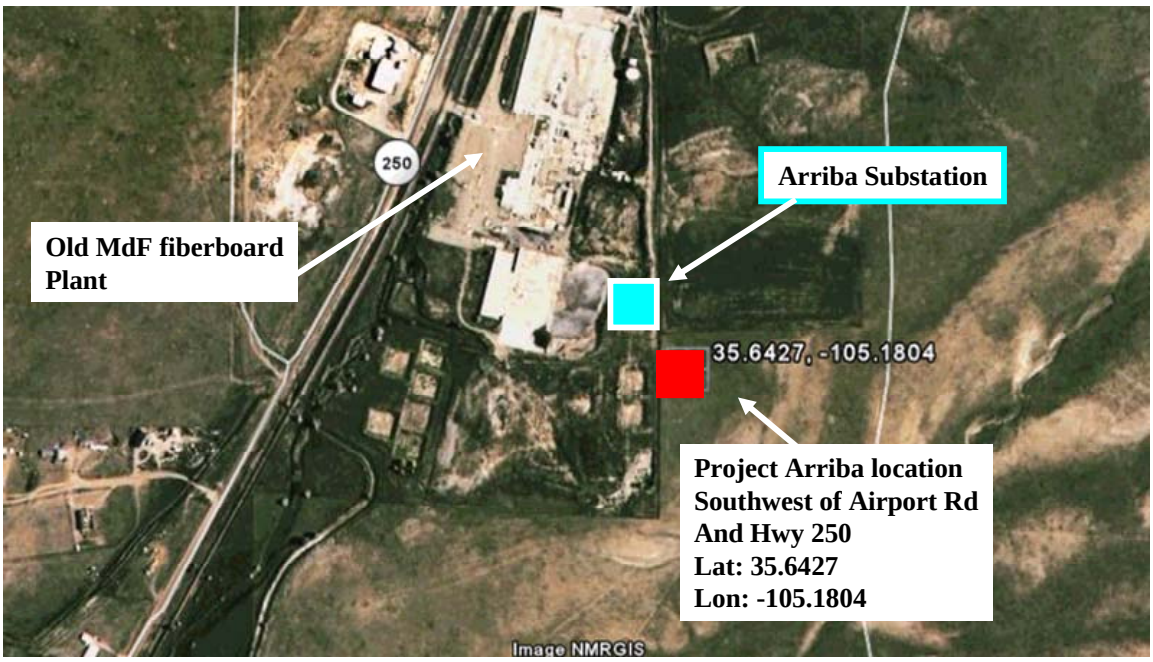
1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Arriba. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Arriba proposes to connect a 5,000 KW AC PV facility to an Arriba Substation Feeder in Las Vegas, NM. The Project will be located southwest of Airport Rd and Hwy 250 as shown in Figure 1. The circuit distance from Arriba Substation to the Project Arriba point of interconnection (POI) is about 400 ft.

***Figure 1* – Project Arriba Location**



3.0 SYSTEM CONFIGURATION

Project Arriba is a large PV source and is proposed to be served by a dedicated feeder. Due the size of the Project output and proximity to Arriba Substation, Distribution Planning proposes that the Project be served by a dedicated feeder from the substation. Arriba Substation presently has only one feeder, Arriba Feeder 11, serving load. Study analysis is based on a dedicated feeder, Arriba Feeder 12, serving the Project. Arriba Feeder 12 is presently not in use. Table 1 shows the rating of Arriba Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Arriba	22.4	24.93	26.54	115-12.47

Table 2 shows the non-coincident peak 2008 peak summer loads for Arriba Substation and feeders.

***Table 2* - July 2008 Non-coincident Peak Loads**

Feeder	July 2008 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Arriba				
Arriba 11	2,942	-683	3,020	-97.4
Arriba 12	0	0	0	
Arriba 13	0	0	0	
Arriba 14	0	0	0	
Arriba Sub	2,942	-683	3,020	-97.4

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Arriba Substation transformer are shown in Table 3:

***Table 3* - Arriba Substation max/min Daylight Hours Load**

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Dec 4, 2008	5 PM	3,701	-837	3,795	-97.5	163	173	187
June 14, 2008	7 AM	1,342	-198	1,357	-98.9	57	63	67

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

Project Arriba, rated output of 5,000 KW, exceeds the load on the Arriba Substation transformer. There is only one feeder, Arriba Feeder 11, on Arriba Substation presently serving load. Table 3 shows the maximum and minimum load on Arriba Feeder 11, which is also the total load on the substation transformer. The maximum load on the Arriba Substation transformer, as shown in Table 3, is less than the rated output of Project Arriba. This will result in electricity flowing from the distribution system through the substation transformer to the transmission system. The voltages on Arriba Feeder 11 are minimally impacted by the Project output because the Project is not connected to Arriba Feeder 11. Of concern are the substation bus voltage and regulation as well as impact on the transmission system.

4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. Project Arriba at maximum output causes the transmission voltage at the substation transformer to increase about 0.008 per unit (0.92 kV on a 115 kV base). The normal voltage is 1.05 per unit (120.75 kV on a 115 kV base). The Las Vegas area transmission voltage is high because transmission capacitor banks in the area are energized to support voltage in the event of a transmission line contingency. This voltage issue does not warrant changing the operation character of the transmission system.

4.2 Voltage impacts for maximum daylight hours load

Project Arriba was modeled as a source directly connected to Arriba Substation using a dedicated feeder, Arriba Feeder 12. The Synergee model included the substation transformer, Arriba Feeder 11 and Arriba Feeder 12. The substation bus voltage and load tap changer position for maximum daylight hours load for 2008 with and without Project Arriba, per the Synergee model, are shown in Tables 4 and 5.

***Table 4* - Arriba Substation without Project Arriba for daylight hours maximum load on December 4, 2008**

	ARRIBA SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.3	124.3	124.3	124.3
LTC position	2 lower	2 lower	2 lower	

The model voltages at the substation bus are shown in Table 4. The voltages at Arriba Substation prior to the installation of Project Arriba are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

***Table 5* - Arriba Substation with Project Arriba for daylight hours maximum load on December 4, 2008**

	ARRIBA SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	123.9	123.9	123.9	123.9
LTC position	3 lower	3 lower	3 lower	

The model voltages at the substation bus are shown in Table 5. The voltages at Arriba Substation after to the installation of Project Arriba are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable.

4.3 Voltage impacts for minimum daylight hours load

The Arriba Feeder 11 voltage for the feeder minimum daylight hours load for 2008 with and without Project Arriba, per the Synergee model, are shown in Graphs 6 and 7.

***Table 6* - Arriba Substation without Project Arriba for daylight hours minimum load on June 14, 2008**

	ARRIBA SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	124.2	124.2	124.2	124.2
LTC position	2 lower	2 lower	2 lower	

The model voltages at the substation bus are shown in Table 6. The voltages at Arriba Substation prior to the installation of Project Arriba are within PNM voltage criteria (ANSI C84.1)

Range A limits and are acceptable. The minimum load was modeled with the one 1,200 KVAR capacitor bank on Arriba Feeder 11 de-energized.

***Table 7* - Arriba Substation without Project Arriba for daylight hours minimum load on June 14, 2008**

	ARRIBA SUBSTATION			
	A-phase	**B-phase**	**C-phase**	**Balanced**
Bus voltage	123.8	123.8	123.8	123.8
LTC position	3 lower	3 lower	3 lower	

The model voltages at the substation bus are shown in Table 7. The voltages at Arriba Substation after to the installation of Project Arriba are within PNM voltage criteria (ANSI C84.1) Range A limits and are acceptable. The minimum load was modeled with the one 1,200 KVAR capacitor bank on Arriba Feeder 11 de-energized.

In conclusion, the voltage on Arriba Substation bus stays within the PNM criteria of ANSI C84.1 regardless of Project Arriba output.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Project Arriba is served by a dedicated source, Arriba Feeder 12, and there is no voltage regulator installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

As seen in Tables 4-7, the Synergee modeling shows the LTC changed 1 position for 5,000 KW source on the dedicated feeder for high or low load periods. This LTC operation is not considered an adverse impact.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Arriba Substation bus was fixed at 123 volts with and without Project Arriba output for maximum and minimum load periods. Table 8 summarizes the balanced voltage and the calculated voltage flicker. Table 9 is based on the GE flicker graph.

Table 8 ***- Voltage flicker on Arriba Substation bus due to Project Arriba***

	Arriba Substation bus Vltage	
	Minimum	**Maximum**
Without Project	122.7	122.8
With Project	123.1	123.2
% Voltage Flicker	**0.33**	**0.33**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

Table 9 ***- Frequency of voltage flicker due to PV output changes***

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
0.33	30/minute	5/second

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 8 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 9. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Arriba POI to the substation were reviewed using the Synergee feeder model with and without Project Arriba's maximum output of 5,000 KW AC.

The proposed conductor for Arriba Feeder 12 is 750 MCM AL from the substation breaker to the POI. The conductor normal rating is 11.5 MVA which is greater than the maximum output of Project Arriba. There will be no conductor loading problem on the dedicated source, Arriba Feeder 12, from the substation to Project Arriba.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. There are no capacitors on the dedicated feeder, Arriba Feeder 12, which serves Project Arriba. Therefore, no capacitor bank switching occurs due to Project Arriba.

9.0 PROTECTION

Arriba Substation Feeder 12 is protected by a 1,200 amp circuit breaker in metal clad switchgear with three GE, IAC53 phase overcurrent relays and one GE, IAC53 ground overcurrent relay. There is also a GE, NLR reclosing relay. The switchgear bus and feeder is protected by three GE, IAC53 phase overcurrent relays and one GE, IAC53 ground relay. The transformer protection is three GE, STD differential relays. Project Arriba system will be connected to the system approximately 400 ft. from the substation.

Fault analysis of the system was conducted to determine the impact of Project Arriba on the feeder protective devices. The PV system was modeled in Synergee to produce the 693 amps of fault current on the 12.47 kV distribution system as noted in the interconnection application.

The impact of Project Arriba fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 5,000 KW AC PV system. Finally, the feeder circuit breaker relay coordination was reviewed. Fault current contributions from the Project do not create any feeder circuit breaker protection mis-coordination issues on the feeder; however the available fault current from the PV system is higher than the ground pickup on the feeder relay. The unit substation protection scheme must be modified to trip the Arriba Feeder 12 breaker for a bus fault.

The Distribution Protection Department requires the substation protection scheme be modified to trip the Arriba Station Feeder 12 breaker to isolate Project Arriba from a substation bus fault.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Arriba output exceeds the minimum and maximum load on Arriba Substation during daylight hours. Therefore, Project Arriba causes a flow of power into Arriba Substation. Analysis determined that no adverse effects were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for

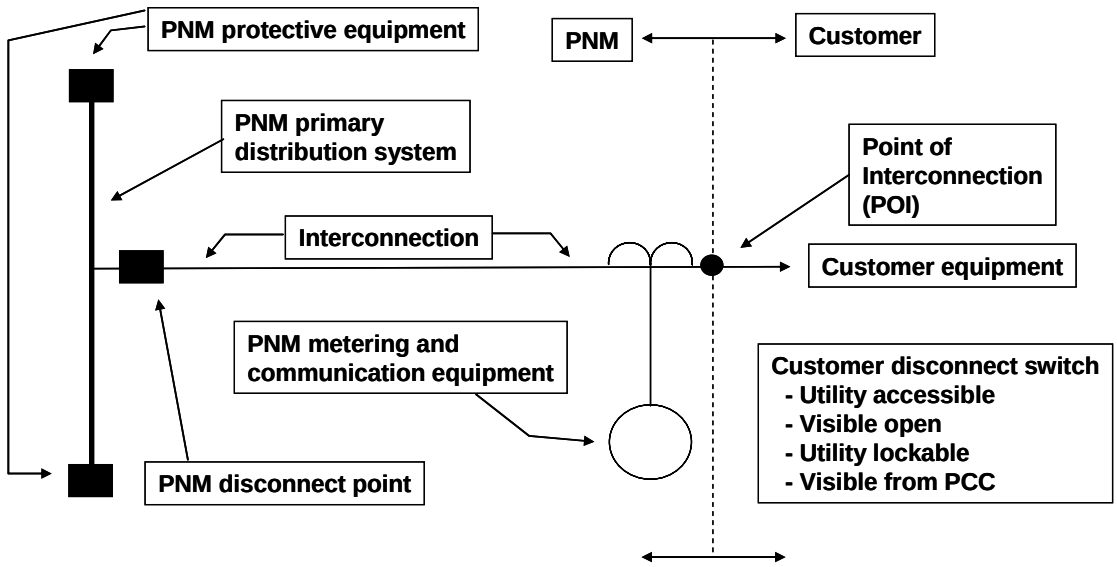
billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 2 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

***Figure 2** – Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a remotely controlled switch. The switch will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The switch may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 10.

***Table 10* - Project Arriba Interconnection Cost**

	ESTIMATED COSTS 2009$
PNM disconnect point*	$ XXX
Interconnection**	$ XXX
PNM metering	$ XXX
Communication	$ XXX
Protection***	$ XXX
TOTAL	**$ XXX**

* PNM disconnect point is an existing substation feeder breaker.
** Extend the distribution primary to the point of interconnection.
*** Substation protection scheme modification.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Arriba does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Arriba Feeder 11. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. There are no remotely controlled capacitor banks on the feeder associated with Project Arriba. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will cause a flow of electricity from the distribution system through the substation transformer, but analysis found there were no adverse impacts on the transmission system. Analysis also shows that the Project output does not cause conductors ratings to be exceeded. Finally, analysis shows that Project Arriba output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Arriba and has determined that there are no adverse impacts associated with a 5,000 KW AC source connected to Arriba Substation with a dedicated distribution primary source of Arriba Feeder 12.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Arriba Substation is maintained within established PNM voltage, equipment and fault protection criteria.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

XXXXX

Project Bonanza 2,000 KW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2008-04)

March 2009

Prepared by:

Public Service Company of New Mexico

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission Distribution/Planning and Contracts.

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EXECUTIVE SUMMARY

The XXXX submitted a 'Small Generator Interconnection Request' for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 2,000 KW AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Bonanza and would be connected to State Pen feeder 13. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW.

The estimated cost of connecting Project Bonanza to the distribution primary is:

	ESTIMATED COSTS 2009$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ XXX	8 months
Interconnection**	$ XXX	8 months
PNM metering	$ XXX	8 months
Communication	$ XXX	8 months
Protection	$ XXX	8 months
TOTAL	**$ XXX**	

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Bonanza does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with State Pen Feeder 13 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud will not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. The remotely controlled capacitor bank on the feeder may potentially be energized. However, there are two RCCS capacitor banks on the feeder and one capacitor bank is currently disabled pending relocation. Once relocated, it will not adversely impact voltages.
6. The Project contribution to fault current requires the State Pen Substation protection scheme be modified to isolate the Project in the event of a substation fault.
7. Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Bonanza and has determined that there are no adverse impacts associated with a 2,000 KW AC source connected to State Pen feeder 13.

Distribution Planning has determined that no other system improvements are required to ensure that electric service to all customers on State Pen feeder 13 is maintained within established PNM voltage, equipment and fault protection criteria. However, the Distribution Protection Department requires the substation protection scheme be modified to trip the State Pen Feeder 13 breaker to isolate Project Bonanza from a substation bus fault.

1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Bonanza. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Bonanza proposes to connect a 2,000 KW AC PV facility to State Pen Substation Feeder 13 in Santa Fe, NM. The project will be located east of NM state penitentiary, north of Camino Justica along Highway 14 as shown in Figure 1. The circuit distance from State Pen Substation to the Project Bonanza point of interconnection (POI) on the existing distribution system is about 8,409 ft. or 1.6 miles.

Figure 1 – Project Bonanza Location

3.0 SYSTEM CONFIGURATION

Project Bonanza is connected to State Pen feeder 13 served from State Pen Substation. Table 1 shows the rating of State Pen Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
State Pen	15.0	15.7	16.7	115-12.47

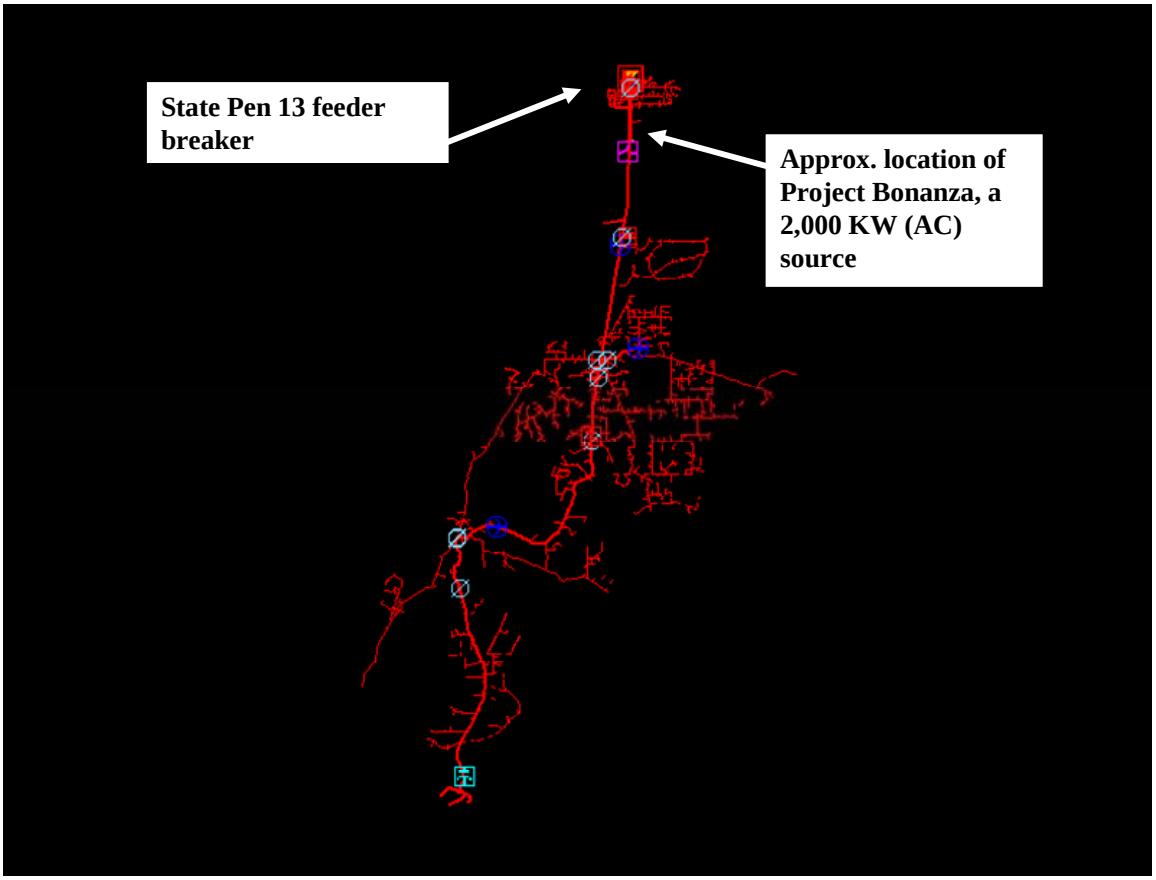
Table 2 shows the non-coincident peak 2008 winter loads for State Pen Substation and feeders.

***Table 2* - January 2008 Non-coincident Peak Loads**

Feeder	January 2008 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
State Pen				
State Pen 11	2,416	-84	2,417	-99.9
State Pen 12	4,274	865	4,361	98.0
State Pen 13	5,329	760	5,383	99.0
State Pen 14	0	0	0	0
State Pen Sub	11,734	1,519	11,832	99.2

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

Figure 2 *– Synergee model of State Pen feeder 13*



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the State Pen Feeder13 are shown in Table 3:

Table 3 ***– State Pen feeder 13 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Dec 15, 2008	6 PM	5445	696	5,489	99.2	227	268	252
June 22, 2008	7 AM	1,713	-106	1,734	-99.8	65	91	82

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

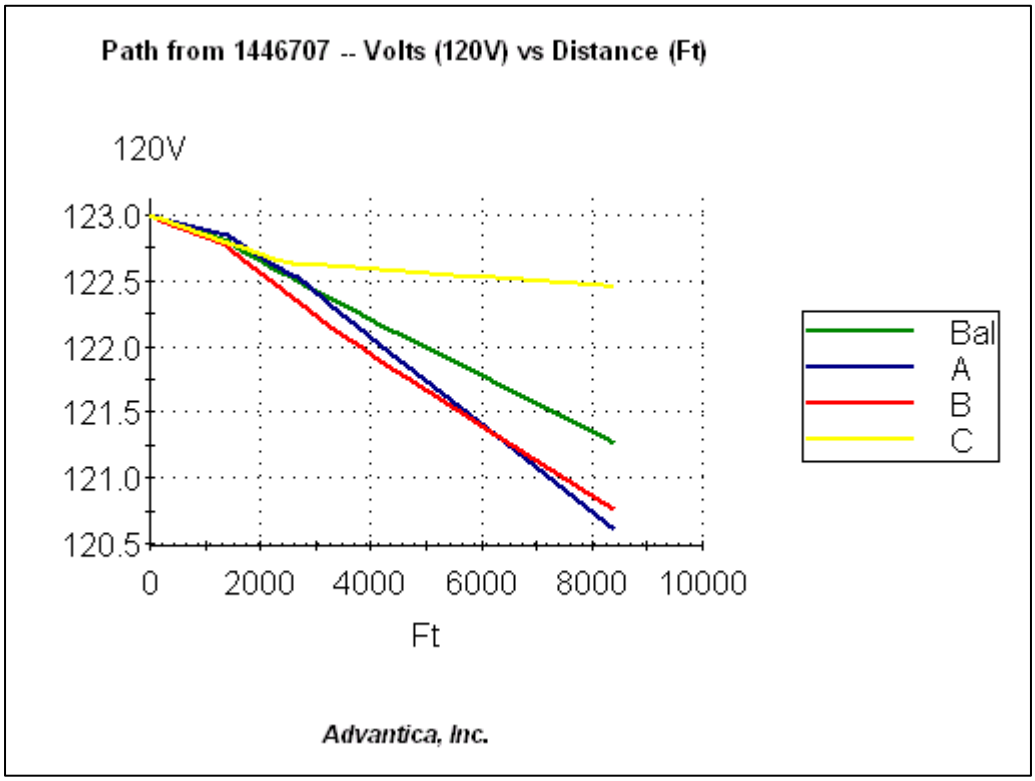
4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. No transmission voltage issues are anticipated associated with Project Bonanza at maximum output.

4.2 Voltage impacts for maximum daylight hours load

The State Pen Feeder13 voltage for the feeder maximum daylight hours load for 2008 with and without Project Bonanza, per the Synergee model, are shown in Graphs 1 and 2.

Graph 1 - State Pen Feeder 13 voltage drop from State Pen Substation to the POI without Project Bonanza for daylight hours maximum load on December 15, 2008

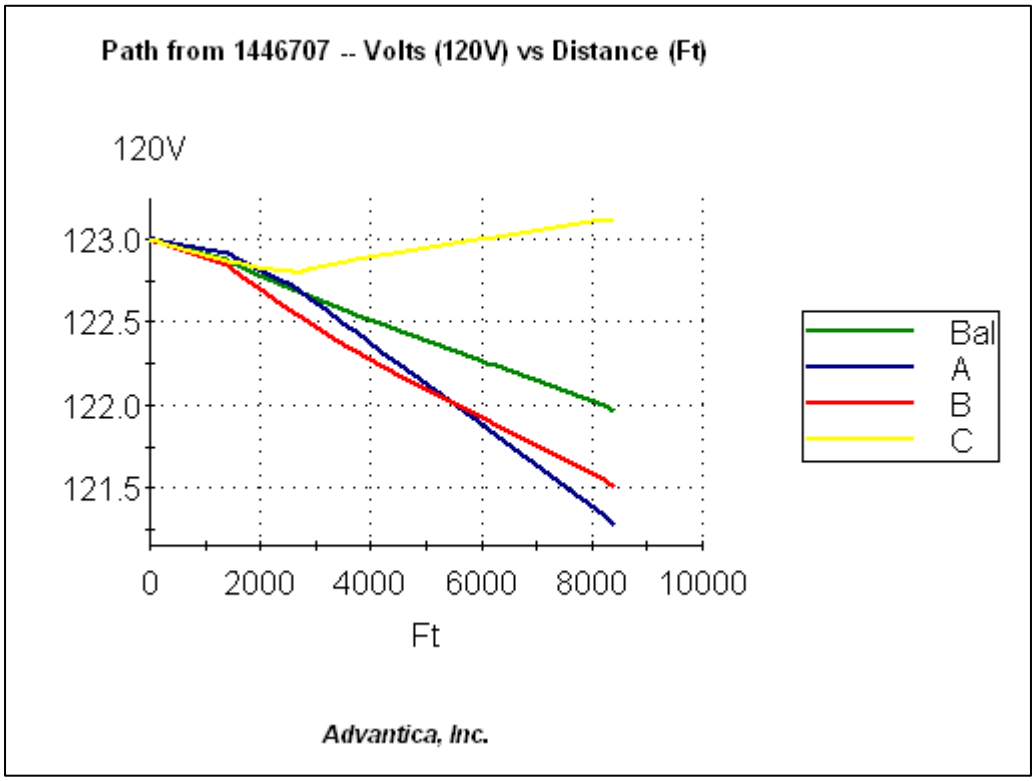


The model voltages at the point of interconnection are:

Phase A – 120.6 volts Phase B – 120.8 volts Phase C – 122.5 volts Balanced – 121.3 volts.

The voltages on State Pen Feeder13 prior to the installation of Project Bonanza are within PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable. The maximum load was modeled without RCCS capacitor bank C35F because it is disabled.

Graph 2 - State Pen Feeder 13 voltage profile from State Pen Substation to the POI with Project Bonanza for daylight hours maximum load on December 15, 2008



The model voltages at the point of interconnection are:

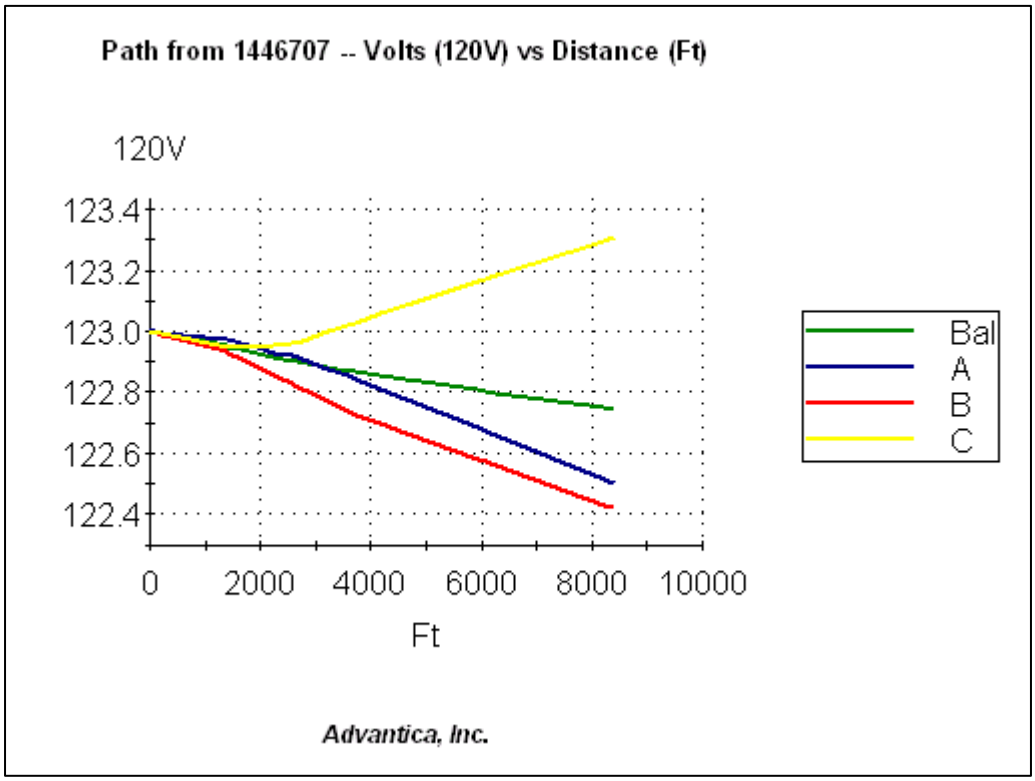
Phase A – 121.3 volts Phase B – 121.5 volts Phase C – 123.1 volts Balanced – 122.0 volts

The voltages on State Pen Feeder13 after the installation of Project Bonanza are within the PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable. The maximum load was modeled without RCCS bank C35F because it is disabled.

4.3 Voltage impacts for minimum daylight hours load

The State Pen Feeder13 voltage for the feeder minimum daylight hours load for 2008 with and without Project Bonanza, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 - State Pen Feeder 13 voltage drop from State Pen Substation to the POI without Project Bonanza for daylight hours minimum load on June 22, 2008

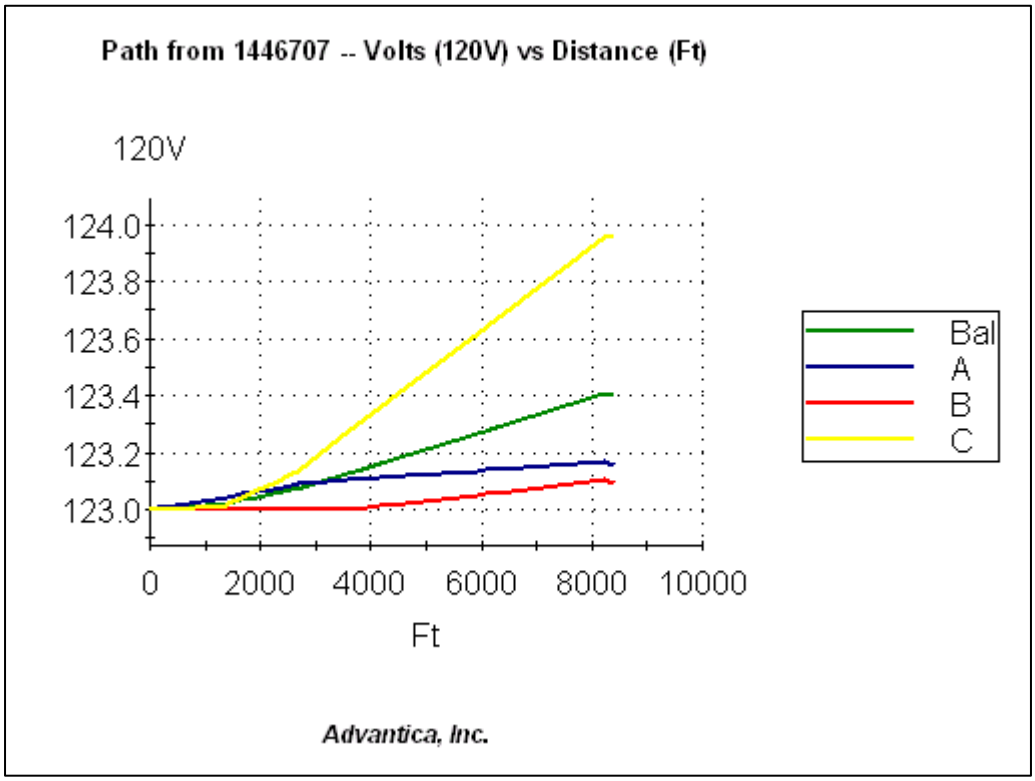


The model voltages at the point of interconnection are:

Phase A – 122.5 volts Phase B – 122.4 volts Phase C – 123.3 volts Balanced – 122.7 volts

The voltages on State Pen Feeder13 prior to the installation of Project Bonanza are within the PNM voltage criteria (ANSI C84.1) Range A at the POI and are acceptable. The minimum load was modeled without RCCS bank C35F because it is disabled.

Graph 4 – State Pen Feeder 13 voltage profile from State Pen Substation to the POI with Project Bonanza for daylight hours minimum load on June 22, 2008



The model voltages at the point of interconnection are:

Phase A – 123.2 volts Phase B – 123.1 volts Phase C – 124.0 volts Balanced – 123.4 volts.

The voltages on State Pen Feeder13 after the installation of Project Bonanza are within the PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable. The minimum load was modeled without RCCS bank C35F because it is disabled.

In conclusion, Project Bonanza output does cause the voltage on State Pen Feeder13 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

State Pen Feeder 13 has three voltage regulators installed on the feeder. The Project connection to the primary distribution system is on the source side of the first voltage regulator on the feeder. Project output may cause the voltage regulator to operate but this is not considered to be an adverse condition. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 2,000 KW source on the feeder would be less than 0.1 volts for high or low load periods. This voltage variance will be insufficient to cause the substation LTC to operate for high or low load on the feeder.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC

does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Bonanza POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

***Table 4* - Voltage flicker on State Pen feeder 13 due to Project Bonanza**

	POI Voltage State Pen feeder 13 Loading	
	Minimum	**Maximum**
Without Project	122.7	121.3
With Project	123.4	122.0
% Voltage Flicker	**0.57**	**0.58**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

***Table 5* - Frequency of voltage flicker due to PV output changes**

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
0.57	1/minute	2/second
0.58	1/minute	2/second

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 4 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 5. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Bonanza POI to the substation were reviewed using the Synergee feeder model with and without Project Bonanza maximum output of 2,000 KW AC.

There were no conductor loading problems from the POI to the substation on State Pen Feeder13 with and without Project Bonanza during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. State Pen Feeder 13 has one 1,200 KVAR RCCS controlled capacitor bank and one 600 KVAR RCCS controlled capacitor bank. The January 2008 peak load on the feeder was 5,329 KW + j 760 KVAR or 5,383 KVA at a 99.0% lagging power factor. The 1,200 KVAR capacitor bank was disabled, pending relocation to another site on State Pen 13.

Project Bonanza at a 2,000 KW AC output would change the apparent feeder loading to 3,329 KW + j 760 KVAR or 3,415 KVA at a 97.5% lagging power factor. This power factor value is outside of the RCCS power factor control point. The RCCS program may adjust the feeder power factor and the 1,200 KVAR capacitor bank would be energized by the RCCS program once it is returned to service.

Project Bonanza may cause a 1,200 KVAR capacitor bank to be energized by the RCCS program for State Pen feeder 13. The switched capacitor bank has been disabled, pending relocation to another site on State Pen Feeder 13.

9.0 PROTECTION

State Pen Substation feeder 13 is protected by a 1,200 amp feeder breaker in metal clad switchgear with three GE, IAC77 phase overcurrent relays and one GE, IAC53 ground overcurrent relay. There is also a GE, NLR reclosing relay. The switchgear bus and feeder backup protection is three GE, IAC53 phase relays and one GE, IAC53 ground relay. The transformer protection is three GE, IJD53 differential relays. The Project Bonanza PV system will be connected to the system approximately 1.6 miles from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in Synergee to produce the 277 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 2,000 KW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder; however the available fault current from the PV system is higher than the ground pickup on the feeder relay. The unit sub protection scheme will be modified to trip the feeder breaker 13 for a bus fault.

Distribution protection requires the substation protection scheme be modified to trip the State Pen Feeder 13 breaker to isolate the Project Bonanza PV system from a substation bus fault. The estimated cost is $750.00.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

The maximum output of Project Bonanza would exceed the minimum load on State Pen Feeder13 during 41 daylight hours based on State Pen Feeder 13 load profile for 2008. However, all 41 hours were in the early morning, 7:00 AM- 8:00 AM, when Project Bonanza output will be at much less then maximum output.

In any case, Project Bonanza never causes a flow of power into State Pen Substation. No State Pen Feeder13 equipment overloads were identified.

11.0 METERING and COMMUNICATION

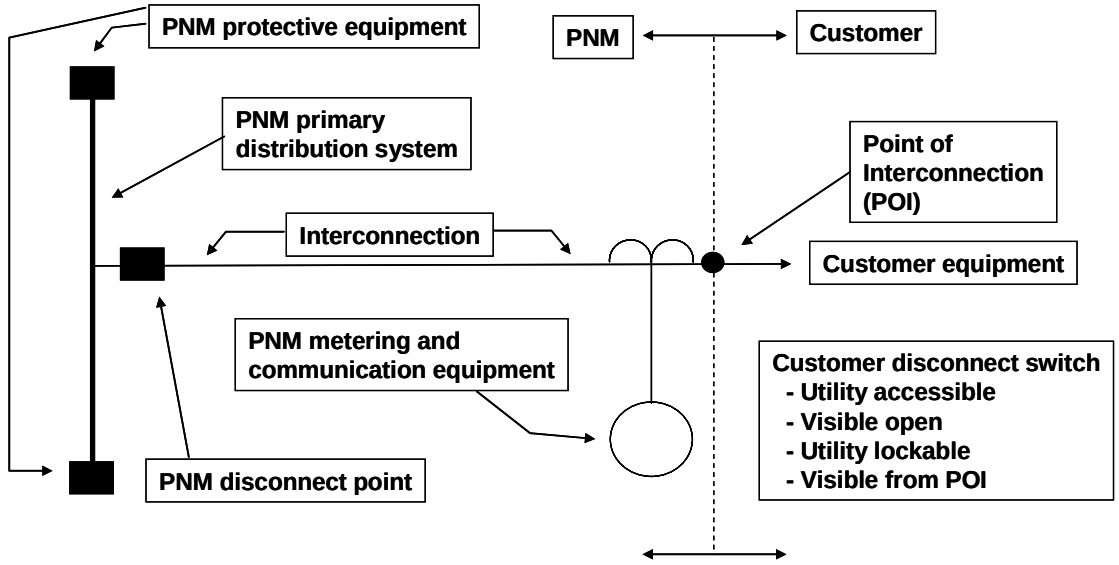
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 6.

Table 6 ***- Project Bonanza Interconnection Cost***

	ESTIMATED COSTS 2009$
PNM disconnect point*	$ XXX
Interconnection**	$ XXX
PNM metering	$ XXX
Communication	$ XXX
Protection	$ XXX
TOTAL	**$ XXX**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple landowners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Bonanza does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with State Pen Feeder13. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Remotely controlled capacitor banks on the feeder may be energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC may cause the LTC to operate. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductor ratings to be exceeded. Finally, analysis shows that Project Bonanza output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Bonanza and has determined that there are no adverse impacts associated with a 2,000 KW AC source connected to State Pen Feeder13.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on State Pen Feeder13 is maintained within established PNM voltage, equipment and fault protection criteria. However, the Distribution Protection Department requires the substation protection scheme be modified to trip the State Pen Feeder 13 breaker to isolate Project Bonanza from a substation bus fault.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

XXXXX

Project Cineneguilla 2,000 KW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2008-05)

March 2009

Prepared by:

Public Service Company of New Mexico

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts.

Any correspondence concerning this document, including technical and commercial questions should be referred to:

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EXECUTIVE SUMMARY

The XXXXX submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 2,000 KW AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Cineneguilla and would be connected to Beckner Feeder 13. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW.

The estimated cost of connecting Project Cineneguilla to the distribution primary is:

	ESTIMATED COSTS $ 2009	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ XXX	8 months
Interconnection**	$ XXX	8 months
PNM metering	$ XXX	8 months
Communication	$ XXX	8 months
Protection	$ XXX	8 months
TOTAL	**$ XXX**	

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Cineneguilla does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Beckner Feeder 13 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud will not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not adversely impact the protection coordination on Beckner Feeder 13.
7. Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Cineneguilla and has determined that there are no adverse impacts associated with a 2,000 KW AC source connected to Beckner Feeder 13.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Beckner Feeder 13 is maintained within established PNM voltage, equipment and fault protection criteria.

1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Cineneguilla. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Cineneguilla proposes to connect a 2,000 KW AC PV facility to Beckner Substation Feeder 13 in Santa Fe, NM. The project will be located north of Airport Road/ Paseo Rael and West of Highway 599 as shown in Figure 1. The circuit distance from Beckner Substation to the Project Cineneguilla point of interconnection (POI) on the existing distribution system is about 31,076 ft. or 5.9 miles.

Figure 1 – Project Cineneguilla Location

3.0 SYSTEM CONFIGURATION

Project Cineneguilla is connected to Beckner Feeder 13 served from Beckner Substation. Table 1 shows the rating of Beckner Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Beckner	22.4	24.12	25.81	115-12.47

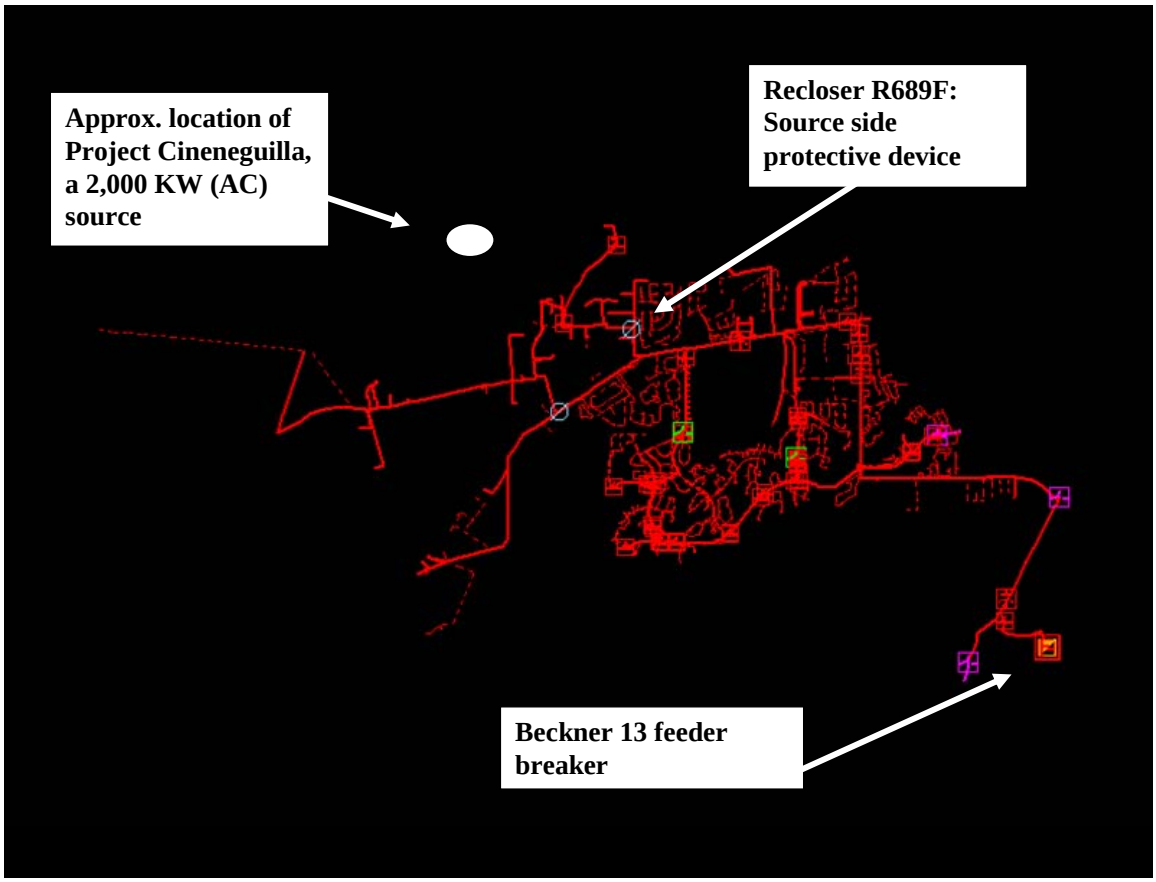
Table 2 shows the non-coincident peak 2008-peak summer loads for Beckner Substation and feeders.

***Table 2* - July 2008 Non-coincident Peak Loads**

Feeder	July 2008 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Beckner				
Beckner 11	5097	264	5103	99.9
Beckner 12	2015	791	2165	93.1
Beckner 13	6468	-1646	6674	-96.9
Beckner 14	0	0	0	0
Beckner Sub	13,063	-338	13,068	-99.9

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

Figure 2 *– Synergee model of Beckner Feeder 13*



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Beckner Feeder13 are shown in Table 3:

Table 3 **– Beckner Feeder 13 max/min Daylight Hours Load**

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Dec 15, 2008	7 PM	8,262	-412	8,272	-99.8	334	440	362
June 22, 2008	7 AM	2,733	-1,826	3,287	-83.1	147	158	149

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

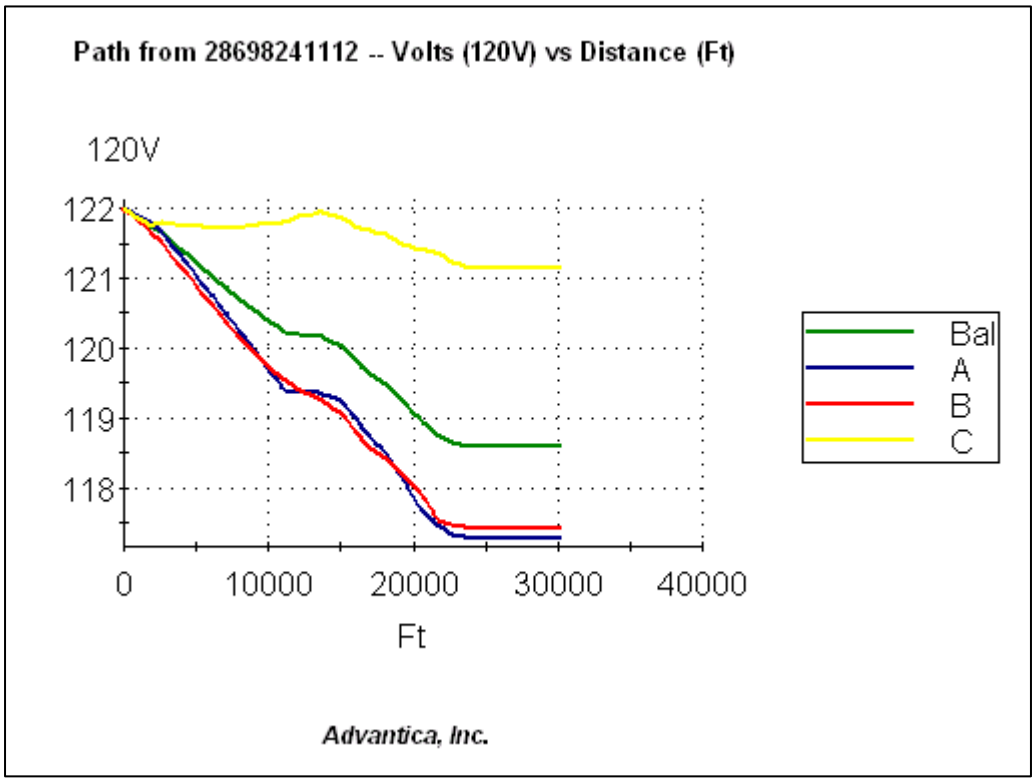
4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. No transmission voltage issues are anticipated associated with Project Cineneguilla at maximum output.

4.2 Voltage impacts for maximum daylight hours load

The Beckner Feeder13 voltage for the feeder maximum daylight hours load for 2008 with and without Project Cineneguilla, per the Synergee model, are shown in Graphs 1 and 2.

Graph 1 - Beckner Feeder 13 voltage drop from Beckner Substation to the POI without Project Cineneguilla for daylight hours maximum load on December 15, 2008

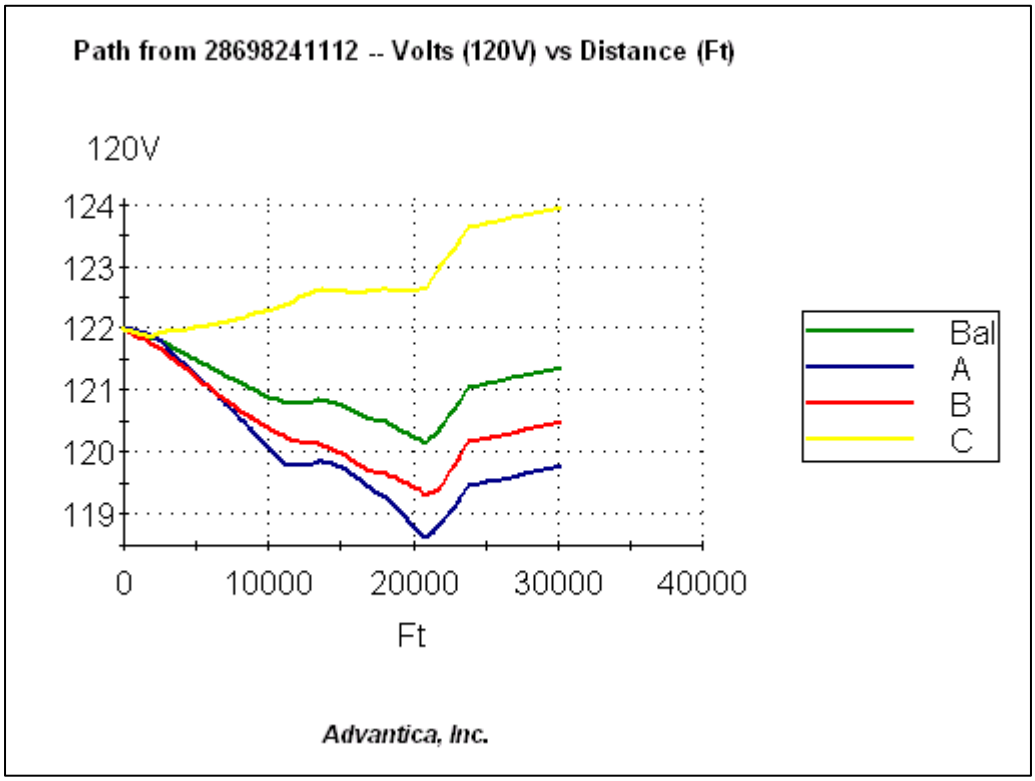


The model voltages at the point of interconnection are:

Phase A – 117.3 volts Phase B – 117.4 volts Phase C – 121.2 volts Balanced – 118.6volts.

The voltages on Beckner Feeder13 prior to the installation of Project Cineneguilla are within PNM voltage criteria (ANSI C84.1) Range B limits at the POI and are acceptable.

Graph 2 - Beckner Feeder 13 voltage drop from Beckner Substation to the POI with Project Cineneguilla for daylight hours maximum load on December 15, 2008



The model voltages at the point of interconnection are:

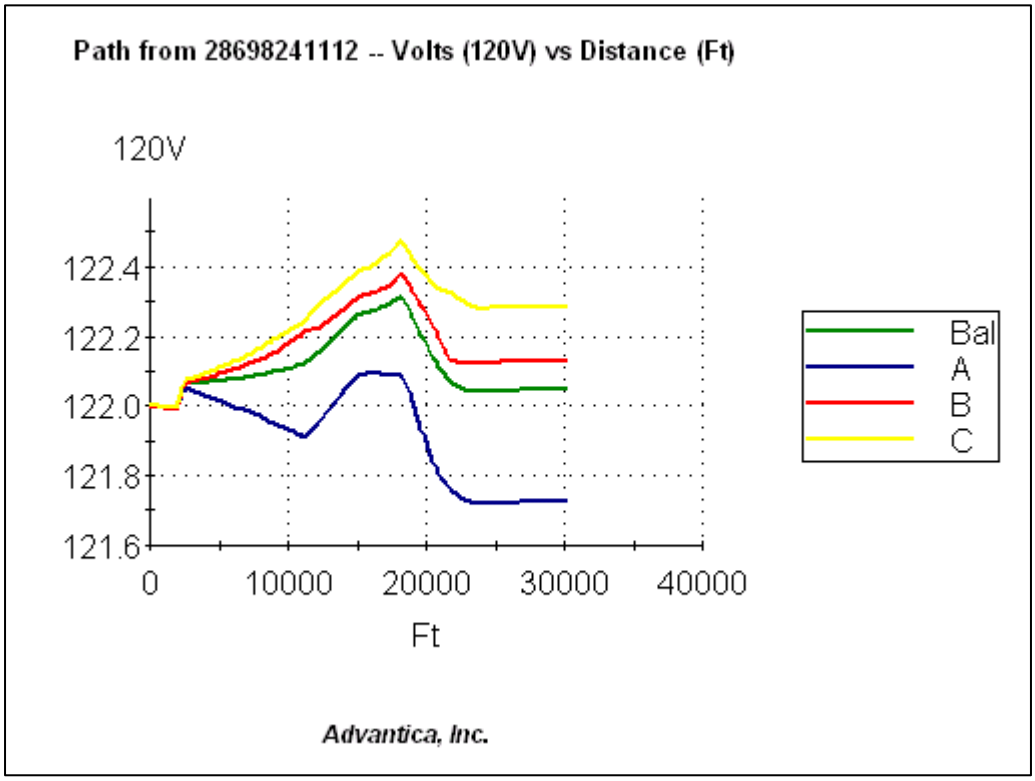
Phase A – 119.8 volts Phase B – 120.5 volts Phase C – 123.9 volts Balanced – 121.4 volts

The voltages on Beckner Feeder13 after the installation of Project Cineneguilla are within the PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable.

4.3 Voltage impacts for minimum daylight hours load

The Beckner Feeder13 voltage for the feeder minimum daylight hours load for 2008 with and without Project Cineneguilla, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 - Beckner Feeder13 voltage drop from Beckner Substation to the POI without Project Cineneguilla for daylight hours minimum load on June 22, 2008

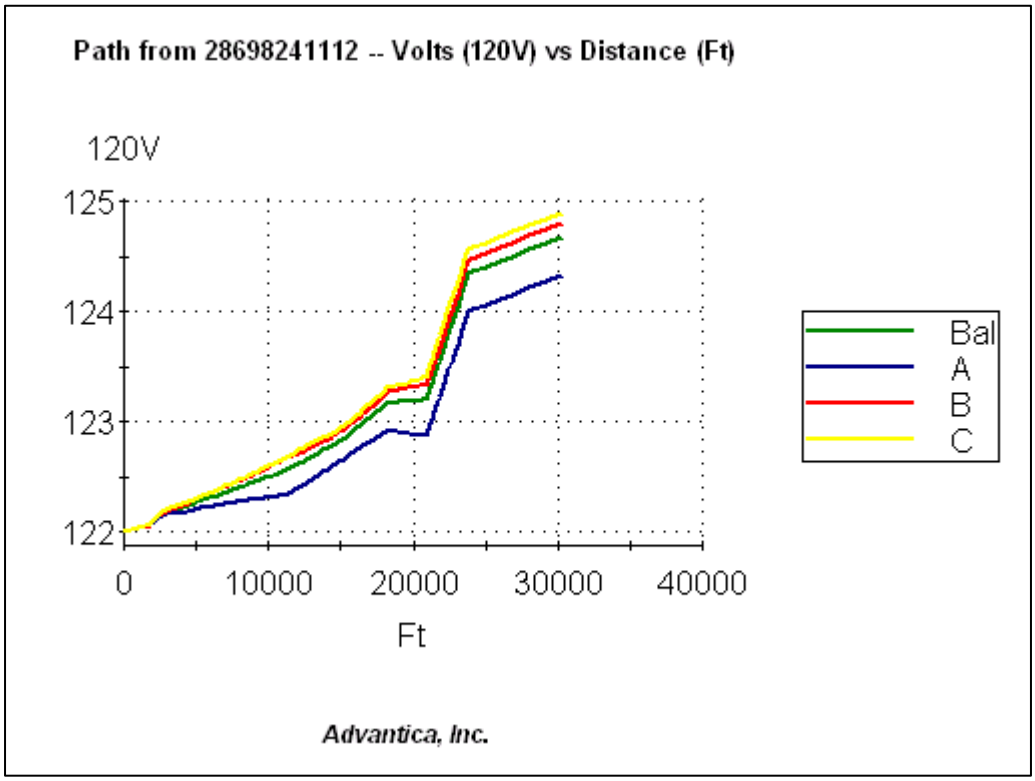


The model voltages at the point of interconnection are:

Phase A – 121.7 volts Phase B – 122.1 volts Phase C – 122.3 volts Balanced – 122.0 volts.

The voltages on Beckner Feeder13 prior to the installation of Project Cineneguilla are within the PNM voltage criteria (ANSI C84.1) Range A at the POI and are acceptable. The minimum load was modeled with one of the three 1,200 KVAR capacitor banks on Beckner Feeder 13 de-energized.

Graph 4 – Beckner Feeder13 voltage drop from Beckner Substation to the POI with Project Cineneguilla for daylight hours minimum load on June 22,2008



The model voltages at the point of interconnection are:

Phase A – 124.3 volts Phase B – 124.8 volts Phase C – 124.9 volts Balanced – 124.7 volts

The voltages on Beckner Feeder13 after the installation of Project Cineneguilla are within the PNM voltage criteria (ANSI C84.1) Range A limits at the POI and are acceptable. The minimum load was modeled with two of the three 1,200 KVAR capacitor banks on Beckner Feeder13 de-energized.

In conclusion, Project Cineneguilla output does cause the voltage on Beckner Feeder13 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Beckner Feeder13 does not have a voltage regulator installed on the feeder. The substation LTC is set at 122 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 120.5 volts and will reduce the voltage if the substation bus is above 123.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 2,000 KW source on the feeder would be 2.5 volts or less for high or low load periods. This voltage variance may cause the substation LTC to operate. This is not anticipated to be an issue.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Cineneguilla POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

***Table 4* - Voltage flicker on Beckner Feeder 13 due to Project Cineneguilla**

	POI Voltage Beckner Feeder 13 Loading	
	Minimum	**Maximum**
Without Project	122.0	118.6
With Project	124.7	121.4
% Voltage Flicker	**2.21**	**2.36**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

***Table 5* - Frequency of voltage flicker due to PV output changes**

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
2.21	2/hour	30/hour
2.36	2/hour	30/hour

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 4 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 5. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Cineneguilla POI to the substation were reviewed using the Synergee feeder model with and without Project Cineneguilla maximum output of 2,000 KW AC.

There were no conductor loading problems from the POI to the substation on Beckner Feeder 13 with and without Project Cineneguilla during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Beckner Feeder13 has three 1,200 KVAR RCCS controlled capacitor banks. The July 2008 peak load on the feeder was 6,468 KW - j 1,646 KVAR or 6,674 KVA at a 96.9% leading power factor. The switched capacitor banks were energized. Project Cineneguilla at a 2,000 KW AC output would change the apparent feeder loading to 4,468 KW - j 1,646 KVAR or 4,762 KVA at a 93.8% leading power factor. This power factor value is outside of the RCCS power factor control point. The RCCS program will likely adjust the feeder power factor and a 1,200 KVAR capacitor would be de-energized by the RCCS program.

Project Cineneguilla will likely cause a 1,200 KVAR capacitor to be de-energized by the RCCS program for Beckner Feeder 13, but no voltage issues were identified and the resulting new power factor would be acceptable.

9.0 PROTECTION

Beckner feeder 13 is protected by a 1,200 amp feeder breaker in metal clad switchgear with a GE, MDP extremely inverse phase overcurrent relay and a very inverse ground overcurrent relay. There is also an ABB, MMCO extremely inverse phase overcurrent relays and a very inverse ground overcurrent relay. There is also a GE, SLR reclosing relay. The switchgear bus and feeder backup protection is a GE, MDP very inverse phase relay and a GE, MDP very inverse ground relay. There is also an ABB, MMCO very inverse phase relay and an ABB, MMCO very inverse ground relay. The transformer protection is three GE, STD differential relays. Approximately 4.13 miles from the substation, there is a Cooper 100 amp recloser. The Cineneguilla Project PV system will be connected to the system approximately 5.9 miles from the substation and 1.8 miles from the recloser on the load side.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The PV system was modeled in Synergee to produce the 277 amps of fault current on the 12.47kV distribution system as noted on the interconnection application.

The first protective device considered was the impact to the Cooper 100 amp recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of the PV system fault current contribution on fuse coordination was studied. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of this 2,000 KW PV system. Finally, the feeder breaker relay coordination was reviewed. Fault current contributions from the PV system do not create any feeder breaker protection mis-coordination issues on the feeder.

Project Cineneguilla contribution to fault current does not adversely impact the protection coordination on Beckner Feeder 13. Thus, no system protection improvements are needed on Beckner Feeder 13.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Cineneguilla output never exceeds the minimum load on Beckner Feeder 13 during daylight hours. Therefore, Project Cineneguilla never causes a flow of power into Beckner Substation. No Beckner Feeder 13 equipment overloads were identified.

11.0 METERING and COMMUNICATION

Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

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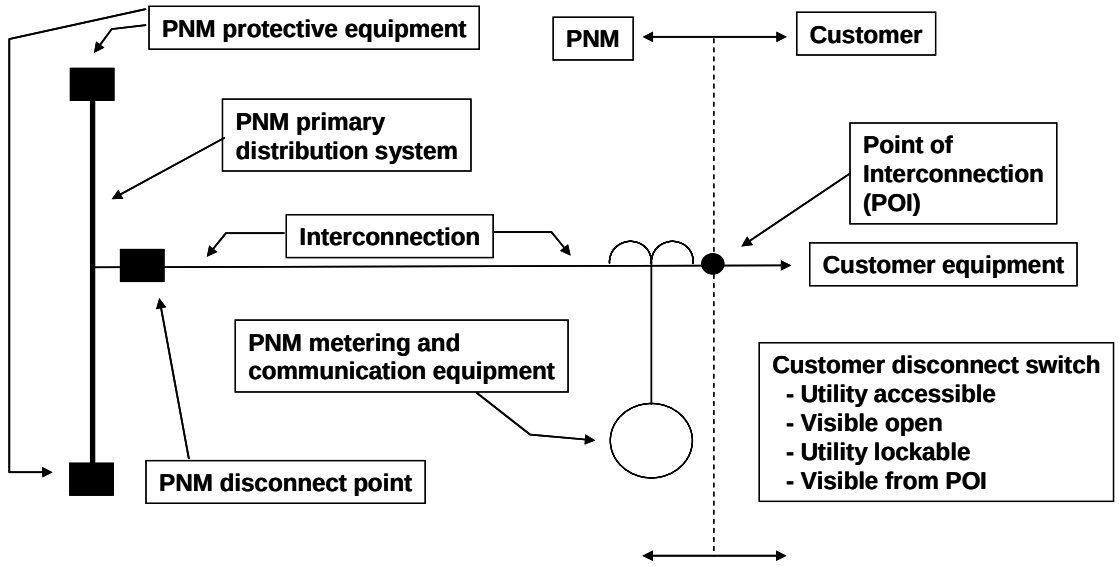
Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

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The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 6.

Table 6 ***- Project Cineneguilla Interconnection Cost***

	ESTIMATED COSTS $ 2009
PNM disconnect point*	$ XXX
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Protection	$ XXX
TOTAL	**$ XXX**

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple landowners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Cineneguilla does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Beckner Feeder 13. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Remotely controlled capacitor banks on the feeder may be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC may cause the LTC to operate but is not anticipated to be an issue. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductor ratings to be exceeded. Finally, analysis shows that Project Cineneguilla output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Cineneguilla and has determined that there are no adverse impacts associated with a 2,000 KW AC source connected to Beckner Feeder13.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Beckner Feeder13 is maintained within established PNM voltage, equipment and fault protection criteria.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

XXXXX

Project Gallinas 1,500 KW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2008-06)

March 2009

Prepared by:

Public Service Company of New Mexico

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts.

Any correspondence concerning this document, including technical and commercial questions should be referred to:

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EXECUTIVE SUMMARY

The XXXXX submitted a Small Generator Interconnection Request for the installation of an inverter based, grid-connected photovoltaic system nominally rated at 1,500 KW AC to the Public Service of New Mexico (PNM) distribution primary system. The request is identified as Project Gallinas and would be connected to Gallinas Feeder 12. An application was submitted based on the Open Access Transmission Tariff of Public Service Company of New Mexico, Attachment J Small Generator Interconnection Procedures (SGIP) for Generator Interconnections Less Than 20 MW.

The estimated cost of connecting Project Gallinas to the distribution primary is:

	ESTIMATED COSTS 2009$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ XXX	8 months
Interconnection**	$ XXX	8 months
PNM metering	$ XXX	8 months
Communication	$ XXX	8 months
Protection	$ XXX	8 months
	$ XXX	
TOTAL	$ XXX	

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Gallinas does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gallinas Feeder 12 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud will not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not adversely impact the protection coordination on Gallinas Feeder 12.
7. Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Gallinas and has determined that there are no adverse impacts associated with a 1,500 KW AC source connected to Gallinas Feeder 12.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gallinas Feeder 12 is maintained within established PNM voltage, equipment and fault protection criteria.

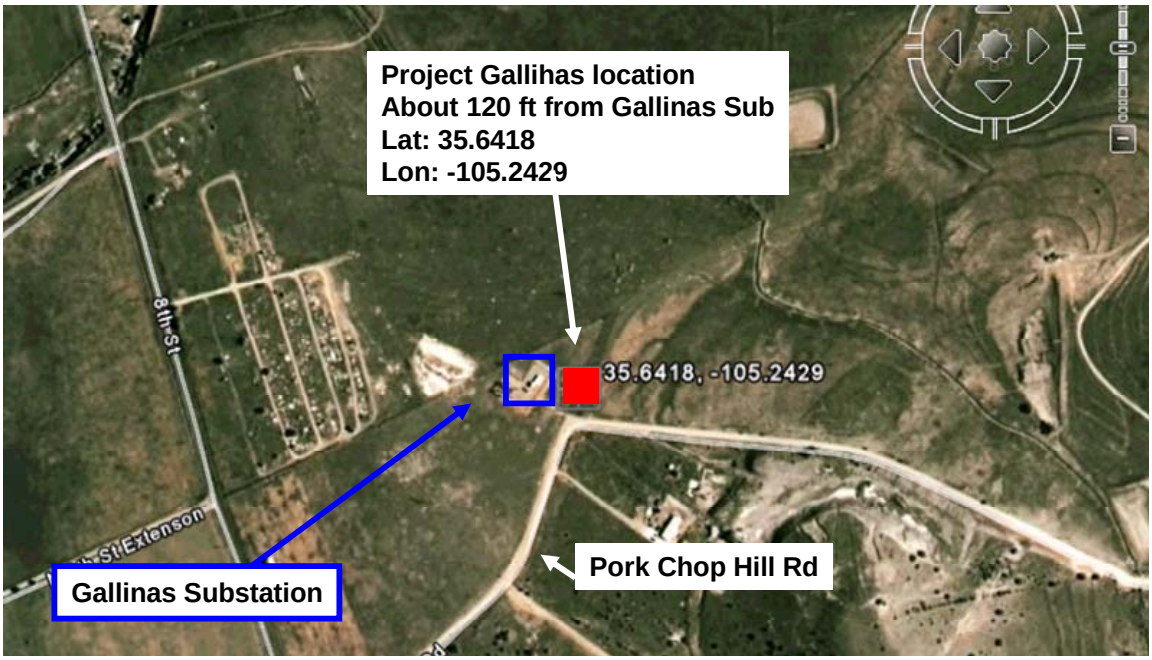
1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Gallinas. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Gallinas proposes to connect a 1,500 KW AC PV facility to Gallinas Substation Feeder 12 in Las Vegas, NM. The Project will be located northwest of Hwy 518 and Pork Chop Hill Rd as shown in Figure 1. The circuit distance from Gallinas Substation to the Project Gallinas point of interconnection (POI) is about 370 ft.

***Figure 1* – Project Gallinas Location**



3.0 SYSTEM CONFIGURATION

Project Gallinas is connected to Gallinas Feeder 12 served from Gallinas Substation. Table 1 shows the rating of Gallinas Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Gallinas	22.4	22.61	24.95	115-12.47

Table 2 shows the non-coincident peak 2008 peak summer loads for Gallinas Substation and feeders.

***Table 2* - July 2008 Non-coincident Peak Loads**

Feeder	July 2008 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Gallinas				
Gallinas 11	4,830	-824	4,900	-98.6
Gallinas 12	4,746	469	4,769	99.5
Gallinas 13	0	0	0	
Gallinas 14	0	0	0	
Gallinas Sub	9,560	947	9,607	99.5

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

Figure 2 ***– Synergee model of Gallinas Feeder 12***

4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Gallinas Feeder 12 are shown in Table 3:

***Table 3* - Gallinas Feeder 12 max/min Daylight Hours Load**

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Jan 16, 2008	6 PM	5,378	-429	5,395	-99.6%	222	273	237
June 1, 2008	7 AM	2,523	-842	2,660	-94.9%	118	129	114

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

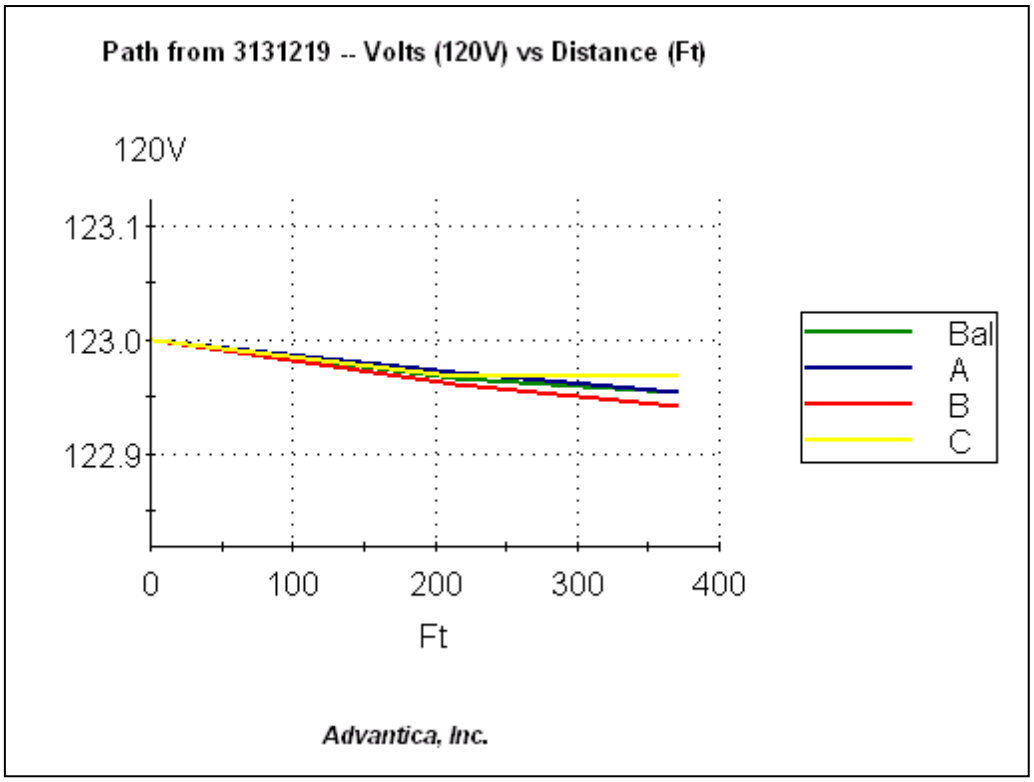
4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. No transmission voltage issues are anticipated associated with Project Gallinas at maximum output.

4.2 Voltage impacts for maximum daylight hours load

The Gallinas Feeder 12 voltage for the feeder maximum daylight hours load for 2008 with and without Project Gallinas, per the Synergee model, are shown in Graphs 1 and 2.

Graph 1 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the POI without Project Gallinas for daylight hours maximum load on January 16, 2008

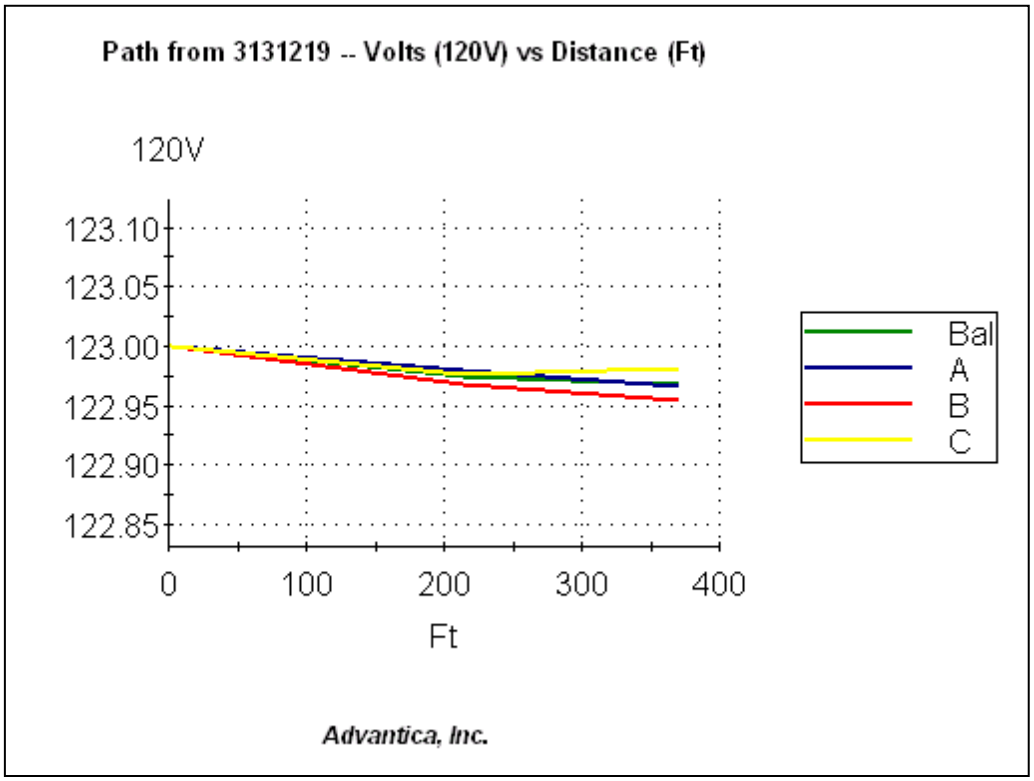


The model voltages at the point of interconnection are:

Phase A – 122.95 volts Phase B – 122.94 volts Phase C – 122.97 volts Balanced – 122.95 volts

The voltages on Gallinas Feeder 12 prior to the installation of Project Gallinas are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the POI with Project Gallinas for daylight hours maximum load on January 16, 2008



The model voltages at the point of interconnection are:

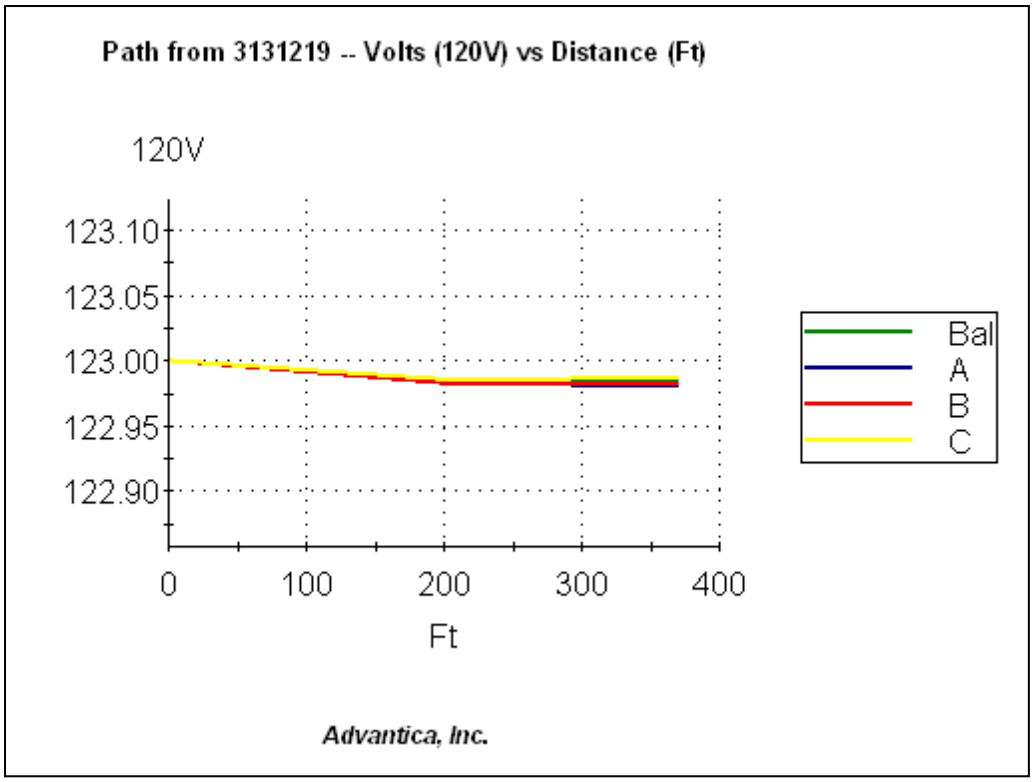
Phase A – 122.97 volts Phase B – 122.95 volts Phase C – 122.98 volts Balanced – 122.97 volts

The voltages on Gallinas Feeder 12 after the installation of Project Gallinas are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.3 Voltage impacts for minimum daylight hours load

The Gallinas Feeder 12 voltage for the feeder minimum daylight hours load for 2008 with and without Project Gallinas, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 - Gallinas Feeder 12 voltage drop from Gallinas Substation to the POI without Project Gallinas for daylight hours minimum load on June 1, 2008

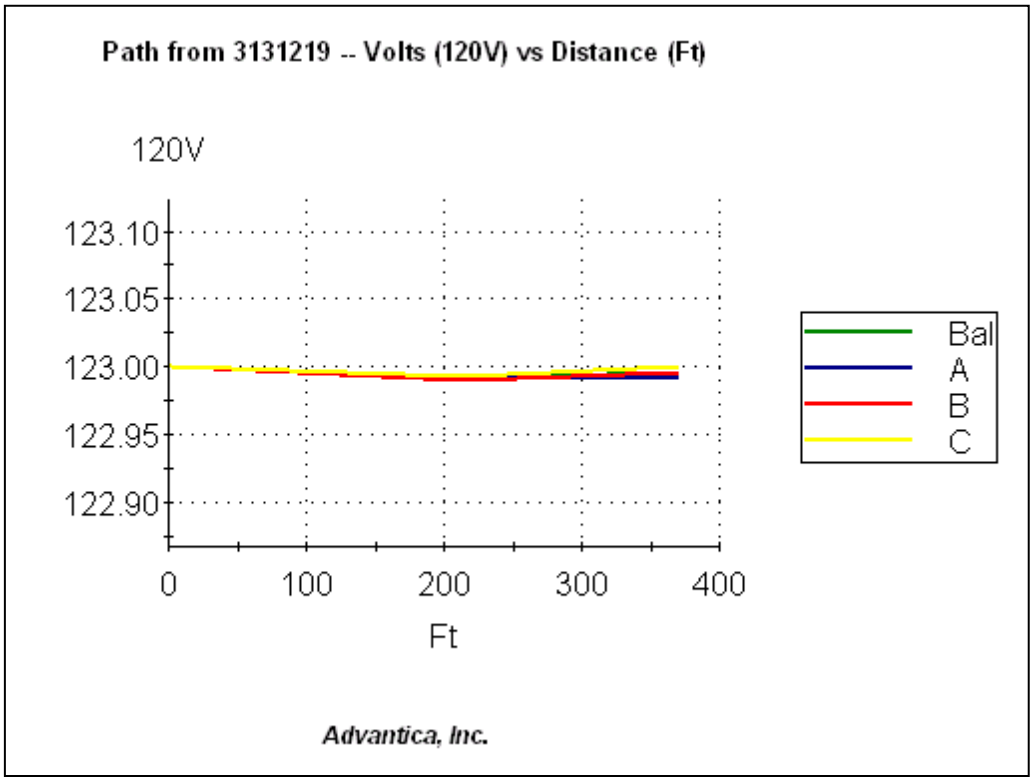


The model voltages at the point of interconnection are:

Phase A – 122.98 volts Phase B – 122.98 volts Phase C – 122.99 volts Balanced – 122.98 volts

The voltages on Gallinas Feeder 12 prior to the installation of Project Gallinas are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 4 – Gallinas Feeder 12 voltage drop from Gallinas Substation to the POI with Project Gallinas for daylight hours minimum load on June 1, 2008



The model voltages at the point of interconnection are:

Phase A – 122.99 volts Phase B – 123.0 volts Phase C – 123.0 volts Balanced – 123.0 volts

The voltages on Gallinas Feeder 12 after the installation of Project Gallinas are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

In conclusion, Project Gallinas output does cause the voltage on Gallinas Feeder 12 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Gallinas Feeder 12 does not have a voltage regulator installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 1,500 KW source on the feeder would be less than 0.1 volts for high or low load periods. This voltage variance will be insufficient to cause the substation LTC to operate for high or low load on the feeder.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Gallinas POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

***Table 4* - Voltage flicker on Gallinas Feeder 12 due to Project Gallinas**

	POI Voltage Gallinas Feeder 12 Loading	
	Minimum	**Maximum**
Without Project	122.98	122.95
With Project	123.00	122.97
% Voltage Flicker	**0.016**	**0.016**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

***Table 5* - Frequency of voltage flicker due to PV output changes**

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
0.016	No limit	No limit
0.016	No limit	No limit

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 4 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 5. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Gallinas POI to the substation were reviewed using the Synergee feeder model with and without Project Gallinas maximum output of 1,500 KW AC.

There were no conductor loading problems from the POI to the substation on Gallinas Feeder 12 with and without Project Gallinas during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Gallinas Feeder 12 has one 1,200 KVAR RCCS controlled capacitor bank. The July 2008 peak load on the feeder was 4,746 KW + j 469 KVAR or 4,769 KVA at a 99.5% lagging power factor. The switched capacitor bank is energized. Project Gallinas at a 1,500 KW AC output would change the apparent feeder loading to 3,246 KW + j 469 KVAR or 3,279 KVA at a 98.9% lagging power factor. This power factor value does not exceed the RCCS power factor control point. The RCCS program would not adjust the feeder power factor and a 1,200 KVAR capacitor would be remain energized by the RCCS program.

Project Gallinas will not cause a 1,200 KVAR capacitor to be de-energized by the RCCS program for Gallinas Feeder 12.

9.0 PROTECTION

Gallinas Substation Feeder 12 is protected by a 1,200 amp circuit breaker in metal clad switchgear with three Westinghouse, CO-11 phase overcurrent relays and one Westinghouse, CO-9 residual ground overcurrent relay. There is also a Westinghouse, RC reclose relay. The switchgear bus and feeder backup protection is three Westinghouse, CO-9 phase relays and one Westinghouse, CO-9 residual ground relay. The transformer protection is three Westinghouse, CA differential relays that trip a lockout relay to open the switchgear main breaker and 115kv circuit switcher. Project Gallinas will be connected to the distribution system approximately 370 ft. from the substation.

Fault analysis of the system was conducted to determine the impact of the PV system connection on the feeder protective devices. The Project was modeled in Synergee to produce the 208 amps of fault current on the 12.47 kV distribution system as noted in the interconnection application.

The first protective device considered was the impact to a downstream Cooper type W, 70 amp recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of Project Gallinas fault current contribution on fuse coordination was evaluated. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of Project Gallinas. Finally, the feeder circuit breaker relay coordination was reviewed. Fault current contributions from Project Gallinas do not create any feeder circuit breaker protection mis-coordination issues on the feeder.

Project Gallinas contribution to fault current does not adversely impact the protection coordination on Gallinas Feeder 12. Thus, no system protection improvements are needed on Gallinas Feeder 12.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Gallinas output never exceeds the minimum load on Gallinas Feeder 12 during daylight hours. Therefore, Project Gallinas never causes a flow of power into Gallinas Substation. No Gallinas Feeder 12 equipment overloads were identified.

11.0 METERING and COMMUNICATION

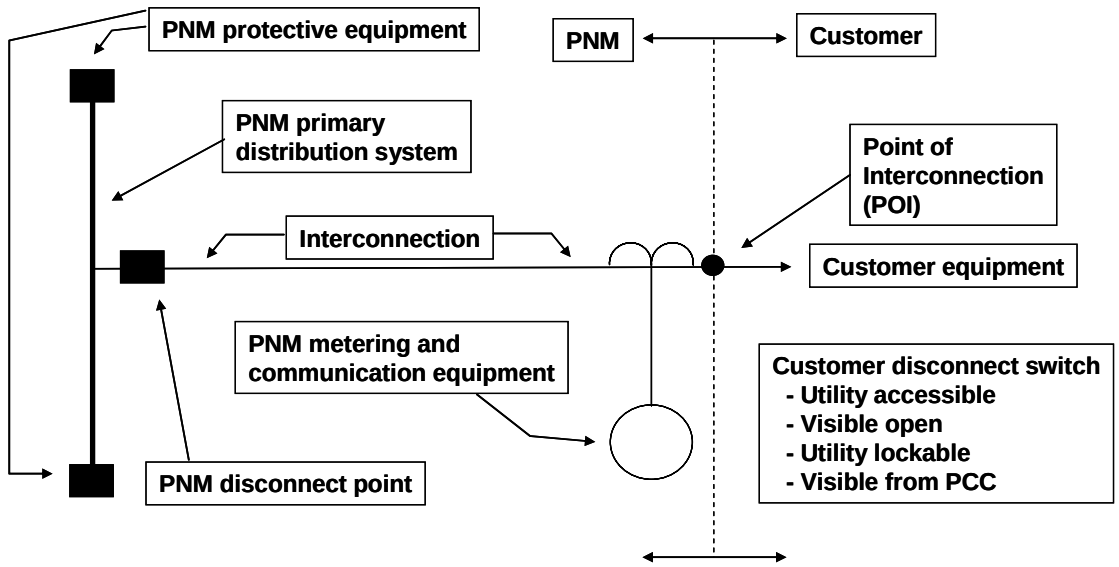
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 6.

Table 6 ***- Project Gallinas Interconnection Cost***

	ESTIMATED COSTS 2009$
PNM disconnect point*	$ XXX
Interconnection**	$ XXX
PNM metering	$ XXX
Communication	$ XXX
Protection	$ XXX
	$ XXX
TOTAL	$ XXX

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Gallinas does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Gallinas Feeder 12. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductors ratings to be exceeded. Finally, analysis shows that Project Gallinas output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Gallinas and has determined that there are no adverse impacts associated with a 1,500 KW AC source connected to Gallinas Feeder 12.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Gallinas Feeder 12 is maintained within established PNM voltage, equipment and fault protection criteria.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

XXXXX

Project Zarca 1,000 KW PV Generation Project

Small Generator Interconnection System Impact Study

(OASIS # SGI-PNM-2008-07)

March 2009

Prepared by:

Public Service Company of New Mexico

Electric Services
Transmission Operations

Foreword

This report was prepared for XXXXX by Public Service Company of New Mexico Transmission/Distribution Planning and Contracts.

Any correspondence concerning this document, including technical and commercial questions should be referred to:

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EXECUTIVE SUMMARY

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The estimated cost of connecting Project Zarca to the distribution primary is:

	ESTIMATED COSTS 2009$	**ESTIMATED CONSTRUCTION TIME**
PNM disconnect point*	$ XXX	8 months
Interconnection**	$ XXX	8 months
PNM metering	$ XXX	8 months
Communication	$ XXX	8 months
Protection	$ XXX	8 months
	$ XXX	
TOTAL	$ XXX	

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.

This system impact study evaluates the electrical system impacts from an interconnection request using an electric generation source connected to the distribution primary system. The photovoltaic (PV) generation source is connected to the distribution primary using a DC/AC inverter. An inverter based, grid-connected generation source will produce electricity that is injected into the distribution primary system and electric system impacts considered were voltage, equipment ratings and fault protection.

Project Zarca does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Baca Feeder 12 and analysis results were:

1. Distribution system voltages will remain within the PNM criteria of ANSI C84.1.
2. Automatic control of voltage by the substation LTC may cause the LTC to operate but this is not an adverse effect.
3. Project output variations due to cloud will not cause voltage flicker problems.
4. Project output does not cause conductors ratings to be exceeded.
5. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages.
6. The Project contribution to fault current does not adversely impact the protection coordination on Baca Feeder 12.
7. Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Zarca and has determined that there are no adverse impacts associated with a 1,000 KW AC source connected to Baca Feeder 12.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Baca Feeder 12 is maintained within established PNM voltage, equipment and fault protection criteria.

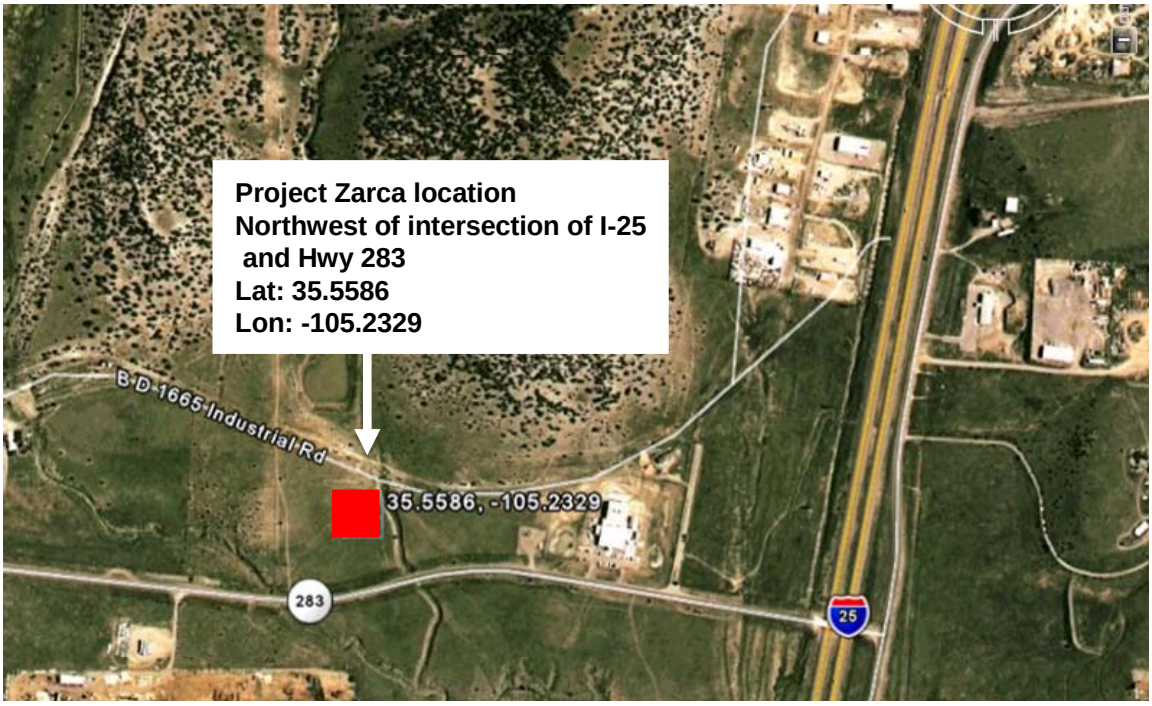
1.0 INTRODUCTION

The purpose of this study is to determine electrical system impacts from a photovoltaic (PV) electric generation source connected to the distribution primary system identified as Project Zarca. The PV generation source will be connected to the distribution primary using an inverter which converts the DC voltage produced by the PV equipment to AC voltage. Electric system impacts considered were voltage, equipment ratings and fault protection. Recommendations will be based on assuring that electric service is provided to all customers within established PNM voltage, equipment loading and fault protection criteria.

2.0 PROJECT LOCATION

Project Zarca proposes to connect a 1,000 KW AC PV facility to Baca Substation Feeder 12 in Las Vegas, NM. The Project will be located northwest of I-25 and Hwy 283 as shown in Figure 1. The circuit distance from Baca Substation to the Project Zarca point of interconnection (POI) is about 26,555 ft. or 5.03 miles.

***Figure 1* – Project Zarca Location**



3.0 SYSTEM CONFIGURATION

Project Zarca is connected to Baca Feeder 12 served from Baca Substation. Table 1 shows the rating of Baca Substation as determined by the EPRI Ptload program.

***Table 1* - Substation transformer nameplate versus Ptload rating**

Substation	Nameplate MVA Rating	Ptload MVA Rating		Voltage Rating
		Normal	Emergency	
Baca	6.25	6.25	6.88	46-12.47

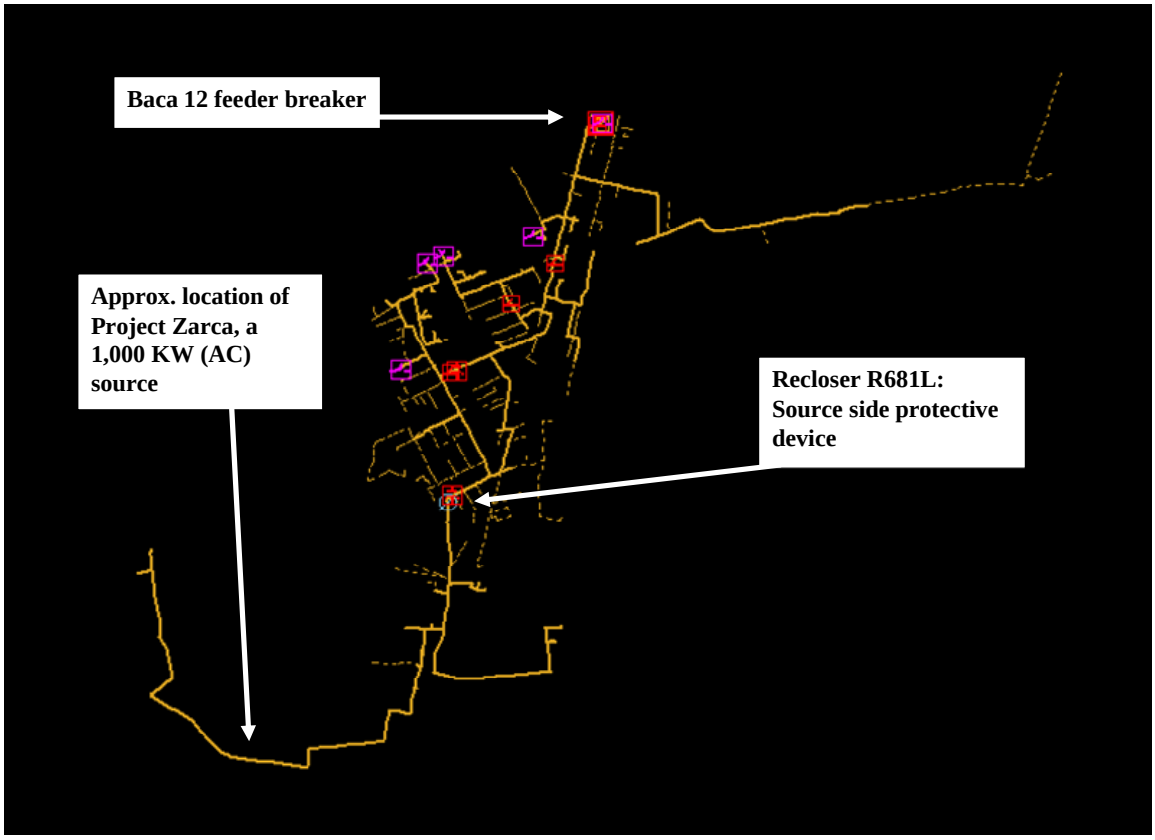
Table 2 shows the non-coincident peak 2008 peak summer loads for Baca Substation and feeders.

***Table 2* - July 2008 Non-coincident Peak Loads**

Feeder	July 2008 Non-coincident Peak Load			
	KW	KVAR	KVA	% Power Factor
Baca				
Baca 11	0	0	0	
Baca 12	4,014	-764	4,086	-98.2
Baca Sub	4,014	-764	4,086	-98.2

Figure 2 is a picture of the distribution feeder used in the Advantica Synergee modeling program.

Figure 2 *– Synergee model of Baca Feeder 12*



4.0 VOLTAGE IMPACT

Voltage impacts associated with a PV grid-connected energy producer were evaluated for two conditions during daylight hours (7AM-7PM) – the first is the peak load on the distribution circuit and the second is the minimum load on the distribution circuit.

The maximum and minimum daylight hours loading on the Baca Feeder 12 are shown in Table 3:

Table 3 ***- Baca Feeder 12 max/min Daylight Hours Load***

DATE	TIME	KW	KVAR	KVA	Power Factor	Phase Amps		
						A	B	C
Jan 24, 2008	6 PM	5,250	508	5,274	99.5%	248	216	253
Aug 30, 2008	7 AM	2,156	-342	2,183	-98.8%	100	100	98

NOTE: The PV system may not be producing maximum output at the time of feeder maximum and minimum load but analysis assumes maximum output.

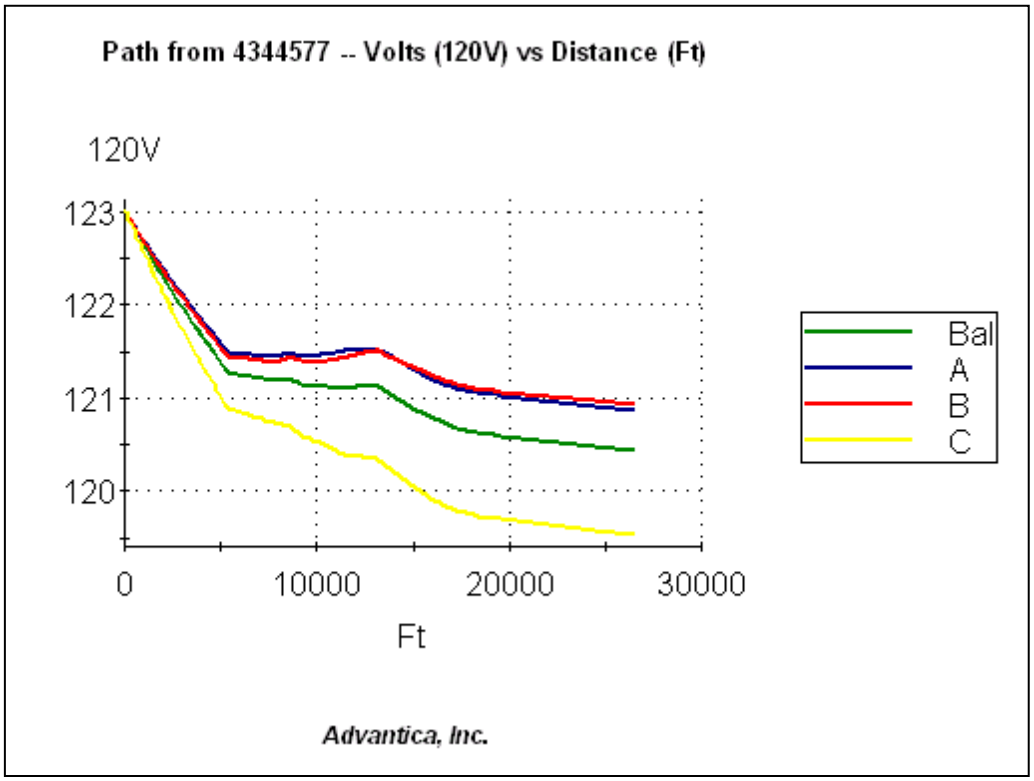
4.1 Voltage impacts on the transmission system

The transmission system was modeled for minimum daylight hours load. No transmission voltage issues are anticipated associated with Project Zarca at maximum output.

4.2 Voltage impacts for maximum daylight hours load

The Baca Feeder 12 voltage for the feeder maximum daylight hours load for 2008 with and without Project Zarca, per the Synergee model, are shown in Graphs 1 and 2.

Graph 1 - Baca Feeder 12 voltage drop from Baca Substation to the POI without Project Zarca for daylight hours maximum load on January 24, 2008

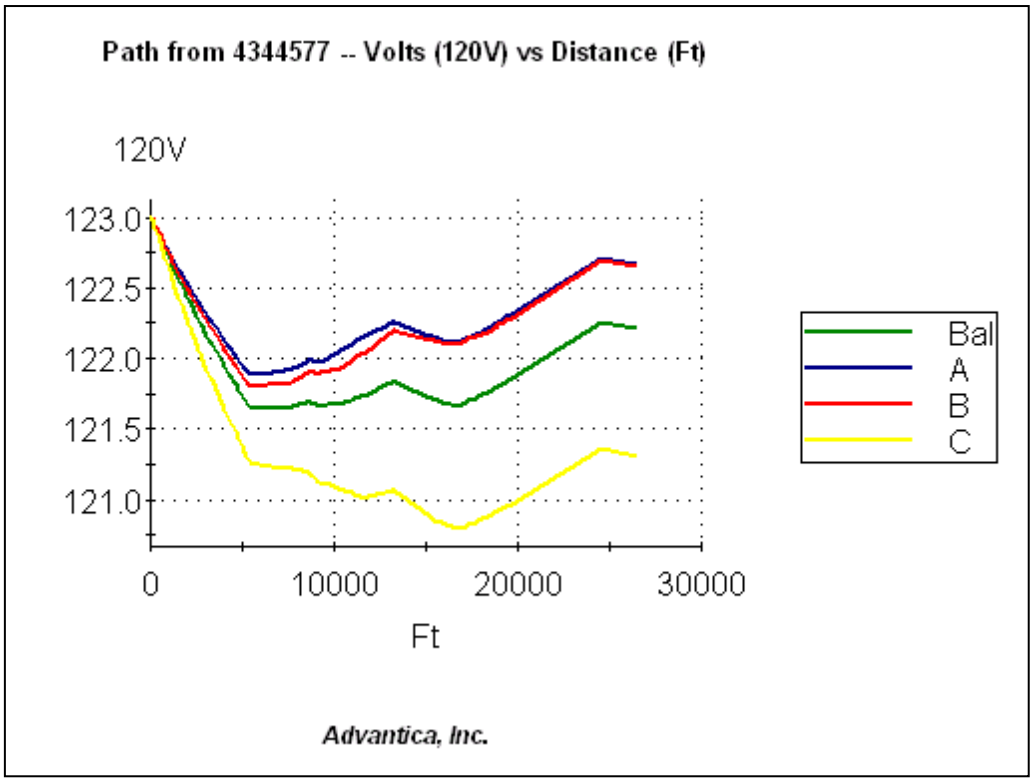


The model voltages at the point of interconnection are:

Phase A – 120.9 volts Phase B – 121.0 volts Phase C – 119.6 volts Balanced – 120.5 volts

The voltages on Baca Feeder 12 prior to the installation of Project Zarca are within PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

Graph 2 - Baca Feeder 12 voltage drop from Baca Substation to the POI with Project Zarca for daylight hours maximum load on January 24, 2008



The model voltages at the point of interconnection are:

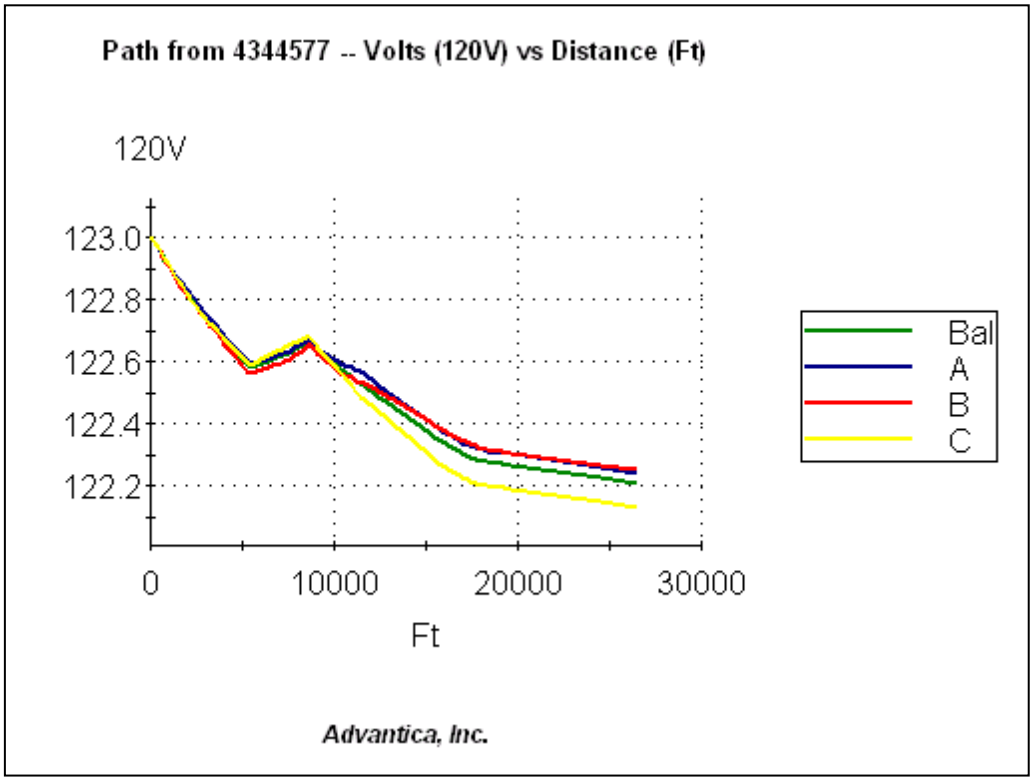
Phase A – 122.7 volts Phase B – 122.7 volts Phase C – 121.4 volts Balanced – 122.3 volts

The voltages on Baca Feeder 12 after the installation of Project Zarca are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable.

4.3 Voltage impacts for minimum daylight hours load

The Baca Feeder 12 voltage for the feeder minimum daylight hours load for 2008 with and without Project Zarca, per the Synergee model, are shown in Graphs 3 and 4.

Graph 3 - Baca Feeder 12 voltage drop from Baca Substation to the POI without Project Zarca for daylight hours minimum load on August 30, 2008

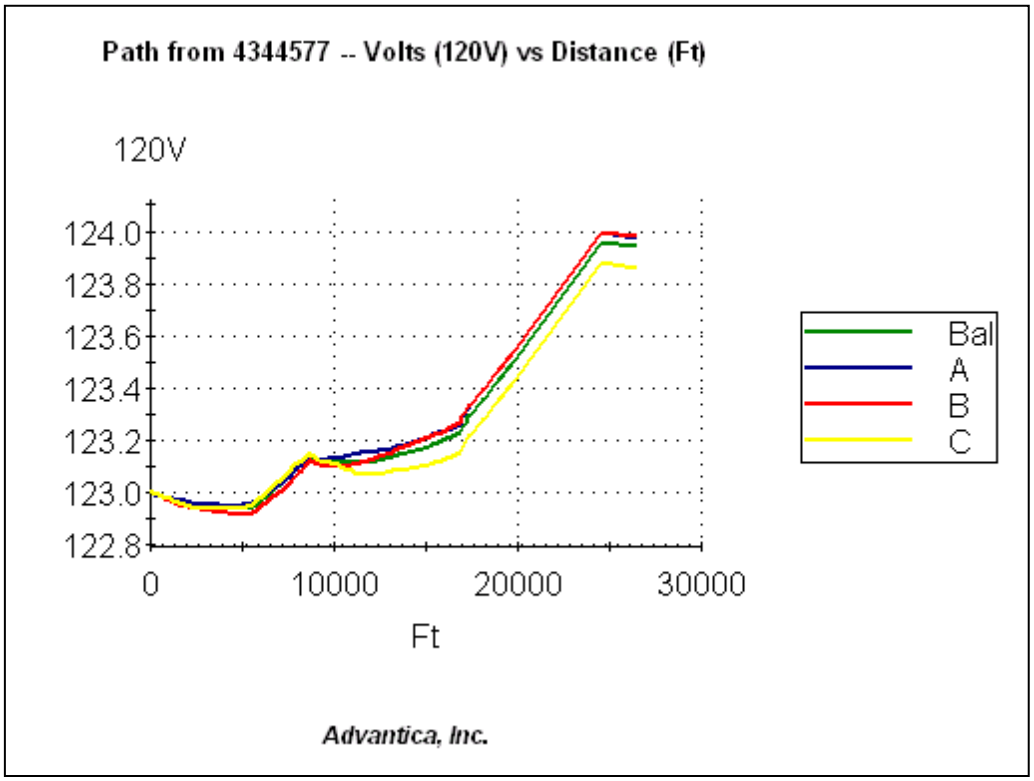


The model voltages at the point of interconnection are:

Phase A – 122.3 volts Phase B – 122.3 volts Phase C – 122.1 volts Balanced – 122.2 volts

The voltages on Baca Feeder 12 prior to the installation of Project Zarca are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on one of the two 1,200 KVAR switched capacitor banks on Baca Feeder 12 being de-energized.

Graph 4 - Baca Feeder 12 voltage drop from Baca Substation to the POI with Project Zarca for daylight hours minimum load on August 30, 2008



The model voltages at the point of interconnection are:

Phase A – 124.0 volts Phase B – 124.0 volts Phase C – 123.9 volts Balanced – 124.0 volts

The voltages on Baca Feeder 12 after the installation of Project Zarca are within the PNM voltage criteria (ANSI C84.1) at the POI and are acceptable. This model is based on one of the two 1,200 KVAR switched capacitor banks on Baca Feeder 12 being de-energized.

In conclusion, Project Zarca output does cause the voltage on Baca Feeder 12 to increase but the voltage stays within the PNM criteria of ANSI C84.1.

5.0 VOLTAGE REGULATION

Voltage regulation on a distribution feeder is done by two methods. The first is by using the load tap changer (LTC) of the substation transformer and the second is the installation of a voltage regulator on a distribution feeder.

Baca Feeder 12 does not have a voltage regulator installed on the feeder. The substation LTC is set at 123 volts with a bandwidth of 3 volts (plus/minus 1.5 volts). The LTC will operate to boost the voltage if the substation bus is below 121.5 volts and will reduce the voltage if the substation bus is above 124.5 volts.

Synergee modeling showed that the voltage variance at the substation due to a 1,000 KW source on the feeder would be about 0.1 volts for high or low load periods. This voltage variance will be insufficient to cause the substation LTC to operate for high or low load on the feeder.

6.0 VOLTAGE FLICKER

Voltage flicker is defined as a voltage variation sufficient in duration to allow visual observation of a change in electric light intensity of an incandescent light bulb. The General Electric Company (GE) developed a graph showing fluctuations per time period versus border line of visibility and border line of irritation.

The output of a PV system is adversely impacted by clouds in the sky. As a cloud shadow passes over a PV system the output will decrease due to the reduction in sunlight. The change in PV system output on a distribution circuit may cause a fluctuation of voltage that might be seen by electric customers. This fluctuation would be classified as a voltage flicker. The most common cause of voltage flicker on the distribution system is due to motor starting. A rapid change in load can not be compensated by the voltage regulation equipment installed on a distribution system. The PNM delay time of a substation LTC is 30 seconds – basically a LTC does not respond to voltage changes until the voltage has been outside of the bandwidth for a minimum of 30 seconds.

As a cloud passes over a PV system the output will decrease to a lower value. Given the amount of PV system output reduction due to clouds is not known the assumption is that it goes to zero and returns to full output once sunlight returns. This mimics the motor starting time.

The voltage at the Project Zarca POI is shown in Section 4.0. Table 4 summarizes the balanced voltage and the calculated voltage flicker. Table 5 is based on the GE flicker graph.

***Table 4* - Voltage flicker on Baca Feeder 12 due to Project Zarca**

	POI Voltage Baca Feeder 12 Loading	
	Minimum	**Maximum**
Without Project	121.7	119.5
With Project	123.4	121.2
% Voltage Flicker	**1.39**	**1.42**

NOTE: % Voltage Flicker calculated as 'With Project' minus 'Without Project' divided by 'Without Project' times 100.

***Table 5* - Frequency of voltage flicker due to PV output changes**

% Voltage Flicker	**Based on GE Flicker curve**	
	Border Line of Visibility	**Border Line of Irritation**
1.39	5/hour	4/minute
1.44	5/hour	4/minute

NOTE: Fluctuation per time period extrapolated from the GE flicker graph.

Project output will vary rather than spike between on and off thus Table 4 results are worst case. Cloud movement is slow thus voltage flicker frequency will be less than the results shown in Table 5. Distribution voltage flicker resulting from changes in Project output is not anticipated to be an issue.

7.0 CONDUCTOR LOADING

Conductor loadings from the Project Zarca POI to the substation were reviewed using the Synergee feeder model with and without Project Zarca's maximum output of 1,000 KW AC.

There were no conductor loading problems from the POI to the substation on Baca Feeder 12 with and without Project Zarca during maximum and minimum loading for daylight hours.

8.0 CAPACITORS

Switching capacitor banks on the PNM distribution system are remotely controlled by the Radio Control Central Station (RCCS) program. The RCCS program polls the System Control and Data Acquisition (SCADA) system for loading information on each distribution feeder to determine if a capacitor bank needs to be switched on or off based on control set points for power factor and capacitor bank size.

An inverter based grid connection will be a real power source (watts only, no vars) for the distribution system. When the inverter is operating the power factor of the distribution feeder will appear to become worse.

RCCS adjusts the power factor of individual feeders. Baca Feeder 12 has two 1,200 KVAR RCCS controlled capacitor banks. The July 2008 peak load on the feeder was 4,014 KW – j 764 KVAR or 4,086 KVA at a 98.2% leading power factor (i.e. 101.8% power factor). Both switched capacitors were energized. Project Zarca at a 1,000 KW AC output would change the apparent feeder loading to 3,014 KW – j 764 KVAR or 3,109 KVA at a 96.5% leading power factor. This power factor value exceeds the RCCS power factor control point. The RCCS program would potentially adjust the feeder power factor and a 1,200 KVAR capacitor may be de-energized by the RCCS program.

Project Zarca may cause a 1,200 KVAR capacitor to be de-energized by the RCCS program for Baca Feeder 12, but no voltage issues were identified and the resulting new power factor would be acceptable.

9.0 PROTECTION

Baca Substation Feeder 12 is protected by a 1,200 amp circuit breaker in metal clad switchgear with a GE, MDP extremely inverse phase overcurrent relay and a very inverse ground overcurrent relay. There is also an ABB, MMCO extremely inverse phase overcurrent relay and a very inverse ground overcurrent relay. There is also a GE, SLR reclosing relay. The Baca Substation transformer is fused on the primary with SMD-2C, 150E fuses. Approximately 2.56 miles from the substation, there is a Cooper 100 amp recloser. Project Zarca will be connected to the distribution system approximately 5.0 miles from the substation and 2.08 miles from the load side of the recloser.

Fault analysis of the system was conducted to determine the impact of Project Zarca on the feeder protective devices. The Project was modeled in Synergee to produce the 139 amps of fault current on the 12.47 kV distribution system as noted in the interconnection application.

The first protective device considered was the impact on the Cooper recloser. The available fault current at the recloser, for faults on the system anywhere on the load side of the recloser is high enough to meet the required safety factor to maintain proper coordination and adequate protection. The impact of Project Zarca fault current contribution on fuse coordination was evaluated. There are no locations on the feeder where the fault current causes mis-coordination with any fusing. No distribution protection equipment ratings are exceeded by the addition of Project Zarca. Finally, the feeder circuit breaker relay coordination was reviewed. Fault current contributions from Project Zarca do not create any feeder circuit breaker protection mis-coordination issues on the feeder.

Project Zarca contribution to fault current does not adversely impact the protection coordination on Baca Feeder 12. Thus, no system protection improvements are needed on Baca Feeder 12.

10.0 FEEDER LOADING

A PV system will only produce electricity during daylight hours. The effects on daylight hours, defined as 7:00 AM to 7:00 PM every day, on the feeder loading were evaluated.

Project Zarca output never exceeds the minimum load on Baca Feeder 12 during daylight hours. Therefore, Project Zarca never causes a flow of power into Baca Substation. No Baca Feeder 12 equipment overloads were identified.

11.0 METERING and COMMUNICATION

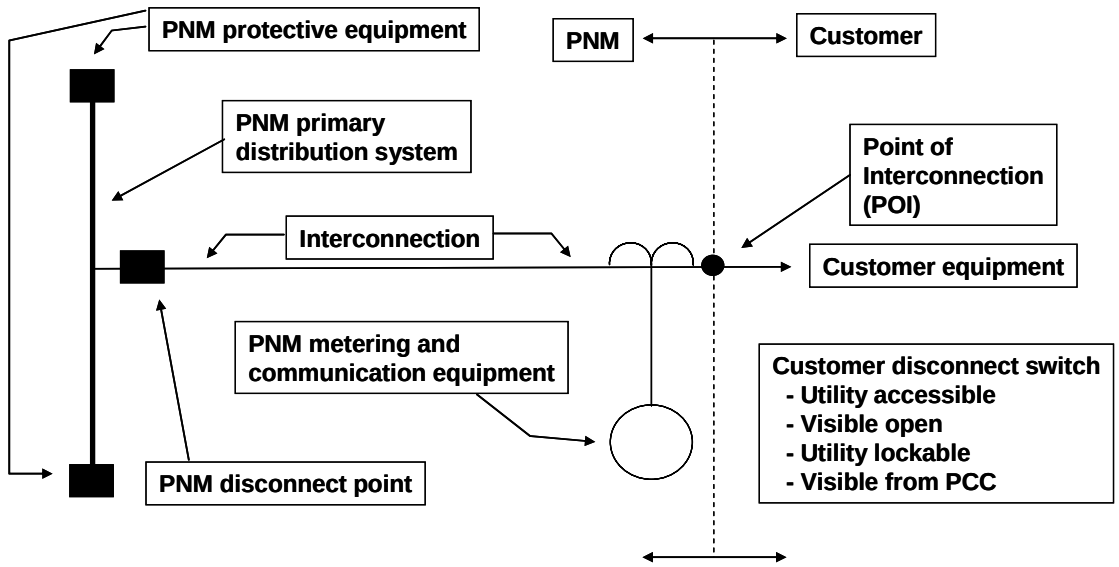
Metering and communication equipment will be located on the Project site within an easement provided by the Project owner. Two revenue quality meters with associated potential and current transformers will be installed for redundancy. Also located at the same point will be communication equipment that will allow PNM to access and down load data from the meter into the PNM system as well as monitor the Project status. The meter information will be used for billing and system status. The status will be for purposes of determining Project KW and KWH output instantaneously and historically.

12.0 TYPICAL CONNECTION CONFIGURATION

Figure 3 is one-line diagram used for illustration purpose of the typical configuration of a grid-connected generator connected to the PNM distribution primary system.

Figure 3 *– Typical Project Interconnection*

Typical connection of a Photovoltaic system to the PNM distribution system



The PNM disconnect point will consist of a SCADA controlled device. The device will allow the Distribution Operations Center to continuously monitor the status of the Project output and remotely disconnect the Project from the electric power system due to system constraints or personnel safety. The device may also provide system protection.

13.0 INTERCONNECTION RELATED COSTS

The preliminary estimated cost to interconnect the facility to the PNM distribution primary is shown in Table 6.

***Table 6* - Project Zarca Interconnection Cost**

	ESTIMATED COSTS 2009$
PNM disconnect point*	$ XXX
Interconnection**	$ XXX
PNM metering	$ XXX
Communication	$ XXX
Protection	$ XXX
	$ XXX
TOTAL	$ XXX

* PNM disconnect point will be a SCADA controlled device.
** Extend the distribution primary to the point of interconnection.

14.0 RIGHT-OF-WAY/EASEMENT ISSUES

Extending the distribution primary to the point of interconnection may involve crossing property of property owners other than the final customer. This will involve acquiring easements from multiple land owners. This should not be an issue but will require time to obtain the easements with final signed documents. If no easements are required other than from the final customer easement acquisition will not be an issue. Permitting the distribution primary construction should not impose any unusual restrictions and is not anticipated to cause a delay in interconnecting the facility with the PNM primary distribution.

15.0 CONCLUSIONS

Project Zarca does not have an adverse impact on the PNM distribution system. The Project location will result in an interconnection with Baca Feeder 12. Analysis shows voltages will remain within the PNM criteria of ANSI C84.1. Remotely controlled capacitor banks on the feeder may potentially be de-energized but this does not adversely impact voltages. The automatic control of voltage by the substation LTC will not cause the LTC to operate. The Project output will not cause a flow of electricity from the distribution system through the substation transformer, thus there is no adverse impact on the transmission system. Analysis also shows that the Project output does not cause conductors ratings to be exceeded. The Project contribution to fault current does not adversely impact the protection coordination on Baca Feeder 12. Finally, analysis shows that Project Zarca output variation will not cause voltage flicker issues for other customers on the distribution system.

Distribution Planning has evaluated the distribution primary system impacts associated with Project Zarca and has determined that there are no adverse impacts associated with a 1,000 KW AC source connected to Baca Feeder 12.

Distribution Planning has determined that no system improvements are required to ensure that electric service to all customers on Baca Feeder 12 is maintained within established PNM voltage, equipment and fault protection criteria.

The application notes that the Xantrex GT 500-480 inverter is presently not UL listed. The application indicates the inverter has passed all UL tests for UL1741 (2005 edition) certification but has not yet been certified. PNM will not move forward with any further facility studies until the applicant provides an inverter listed with a nationally recognized testing and certification laboratory (NRTL) compliant with UL1741 standards. The information needed to perfect the application should include any appropriate drawing changes and reference materials needed to support the final binding agreements to interconnect.