Generation Interconnection System Impact Study Report

For

PJM Generation Interconnection Request Queue Position AD2-171

Branchburg - Alburtis 500kV

June 2019

Preface

The intent of the System Impact Study is to determine a plan, with approximate cost and construction time estimates, to connect the subject generation interconnection project to the PJM network at a location specified by the Interconnection Customer. As a requirement for interconnection, the Interconnection Customer may be responsible for the cost of constructing: Network Upgrades, which are facility additions, or upgrades to existing facilities, that are needed to maintain the reliability of the PJM system. All facilities required for interconnection of a generation interconnection project must be designed to meet the technical specifications (on PJM web site) for the appropriate transmission owner.

In some instances an Interconnection Customer may not be responsible for 100% of the identified network upgrade cost because other transmission network uses, e.g. another generation interconnection or merchant transmission upgrade, may also contribute to the need for the same network reinforcement. The possibility of sharing the reinforcement costs with other projects may be identified in the Feasibility Study, but the actual allocation will be deferred until the System Impact Study is performed.

The System Impact Study estimates do not include the feasibility, cost, or time required to obtain property rights and permits for construction of the required facilities. The project developer is responsible for the right of way, real estate, and construction permit issues. For properties currently owned by Transmission Owners, the costs may be included in the study.

General

Abatis Advisors, LLC, the Interconnection Customer (IC), has proposed a Natural Gas generating facility located in Hunterdon County, New Jersey. The installed facilities will have a total capability of 700 MW with 700 MW of this output being recognized by PJM as capacity. The proposed in-service date for this project is June 1, 2023. **This study does not imply a PSE&G commitment to this in-service date.**

Point of Interconnection

AD2-171 will interconnect with the PJM transmission system along the Alburtis- Branchburg 500kV Line.

Cost Summary

The AD2-171 project will be responsible for the following costs:

Description	Total Cost
Attachment Facilities	$ 2,062,352
Direct Connection Network Upgrades	$ 31,200,326
Non Direct Connection Network Upgrades	$ 36,597,724
Allocation for New System Upgrades	$ 0
Contribution for Previously Identified Upgrades	$ 0
Total Costs	**$ 69,860,402**

Attachment Facilities

The total preliminary cost estimate for the Attachment work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Activity Cost
PSEG: Install attachment facility line and associated hardware to accept the Interconnection Customer generator lead line terminating at the AD2-171 Interconnection substation. And install revenue metering. PJM Network Upgrade #n6092	$ 2,062,352
Total Attachment Facility Costs	**$ 2,062,352**

Direct Connection Cost Estimate

The total preliminary cost estimate for the Direct Connection work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Activity Cost
PSEG: AD2-171 Interconnection Substation. Install a new 500kV three breaker ring bus substation along the Alburtis-Branchburg 500kV Line. PJM Network Upgrade #n6093	$ 31,200,327
Total Direct Connection Facility Costs	**$ 31,200,327**

Non-Direct Connection Cost Estimate

The total preliminary cost estimate for the Non-Direct Connection work is given in the table below. These costs do not include CIAC Tax Gross-up.

Description	Activity Cost
[PSEG] Loop the Branchburg - Alburtis 500kV circuit into the AD2-171 interconnection switching station. PJM Network Upgrade #n6094	$ 36,286,864
[PPL Electric Utilities] Alburtis 500kV Substation: • Modify the existing Branchburg 500kV circuit breaker protection and control scheme. • Modify the existing Branchburg- Breinigsville tie 500kV circuit breaker protection and control scheme. • Perform system checks and test equipment before placing in service. • PJM Network Upgrade #n6096	$ 155,430
[PSEG] Branchburg 500kV Substation: • Modify the existing Alburtis 500kV circuit breaker protection and control scheme & tie breaker protection and control scheme. • Perform system checks and test equipment before placing in service. • PJM Network Upgrade #n6095	$ 155,430

Description	Activity Cost
Total Non-Direct Connection Facility Costs	**$ 36,597,724**

PSEG Scope of Work Assumptions:

- Cost of purchased property and laydown area is excluded.
- The estimate excludes any work associated with removal of contaminated materials and hazardous waste that may be encountered. This includes handling, removal, and disposal.
- Environmental remediation is excluded.
- Any work associated with threatened or endangered species is excluded.

PPL Scope of Work Assumptions:

- Prior to this project a single fiber path between Alburtis and Branchburg will be established and the Alburtis – Branchburg 500kV line protection will be fiber based.
- For any operational, governmental, and/or environmental regulatory delays, the use of additional resources, such as overtime, premiums for expedited material, and/or contractor labor, may enable PPL EU to decrease this construction period but no guarantees can be made. It is also assumed that all rights-of-way and easements are secured by the anticipated construction start dates.

Interconnection Customer Requirements

1. An Interconnection Customer entering the New Services Queue on or after October 1, 2012 with a proposed new Customer Facility that has a Maximum Facility Output equal to or greater than 100 MW shall install and maintain, at its expense, phasor measurement units (PMUs). See Section 8.5.3 of Appendix 2 to the Interconnection Service Agreement as well as section 4.3 of PJM Manual 14D for additional information.

2. The Interconnection Customer may be required to install and/or pay for metering as necessary to properly track real time output of the facility as well as installing metering which shall be used for billing purposes. See Section 8 of Appendix 2 to the Interconnection Service Agreement as well as Section 4 of PJM Manual 14D for additional information.

Revenue Metering and SCADA Requirements

<u>PJM Requirements</u>

The Interconnection Customer will be required to install equipment necessary to provide Revenue Metering (KWH, KVARH) and real time data (KW, KVAR) for IC’s generating Resource. See PJM Manuals M-01 and M-14D, and PJM Tariff Sections 24.1 and 24.2.

Public Service Electric and Gas (PSE&G) Requirements

The Interconnection Customer will be required to comply with all PSE&G Revenue Metering Requirements for Generation Interconnection Customers. The Revenue Metering Requirements may be found within the "Information and Requirements for Electric Service" document located at the following links:

http://www.pseg.com/business/builders/new_service/before/

http://www.pjm.com/planning/design-engineering/to-tech-standards.aspx

Network Impacts

The Queue Project AD2-171 was evaluated as a 700.0 MW (Capacity 700.0 MW) injection tapping the Branchburg to Alburtis 500kV line in the PSEG area. Project AD2-171 was evaluated for compliance with applicable reliability planning criteria (PJM, NERC, NERC Regional Reliability Councils, and Transmission Owners). Project AD2-171 was studied with a commercial probability of 100%. Potential network impacts were as follows:

Summer Peak Analysis - 2021

Generator Deliverability

(Single or N-1 contingencies for the Capacity portion only of the interconnection)

None.

Light Load Analysis

Light Load Studies to be conducted during later study phases (applicable to wind, coal, nuclear, and pumped storage projects).

None.

Multiple Facility Contingency

(Double Circuit Tower Line contingencies were studied for the full energy output. The contingencies of Line with Failed Breaker and Bus Fault will be performed for the Impact Study.)

None.

Short Circuit

(Summary of impacted circuit breakers)

None.

Contribution to Previously Identified Overloads

(This project contributes to the following contingency overloads, i.e. "Network Impacts", identified for earlier generation or transmission interconnection projects in the PJM Queue)

None.

Steady-State Voltage Requirements

(Summary of the VAR requirements based upon the results of the steady-state voltage studies)

None. See Attachment 2

Stability and Reactive Power Requirement for Low Voltage Ride Through

(Summary of the VAR requirements based upon the results of the dynamic studies)

None. See Attachment 2

Affected System Analysis & Mitigation

NYISO Impacts:

NYISO Impacts to be determined during later study phases (as applicable).

New System Reinforcements

(Upgrades required to mitigate reliability criteria violations, i.e. Network Impacts, initially caused by the addition of this project generation)

None.

Contribution to Previously Identified System Reinforcements

(Overloads initially caused by prior Queue positions with additional contribution to overloading by this project. This project may have a % allocation cost responsibility which will be calculated and reported for the Impact Study)

None.

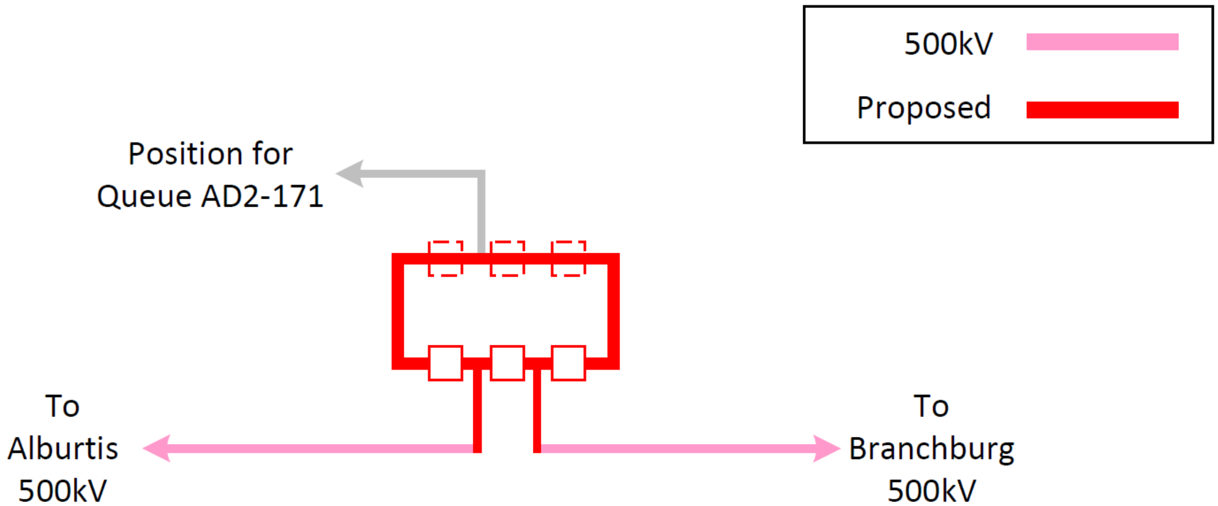
Potential Congestion due to Local Energy Deliverability

PJM also studied the delivery of the energy portion of this interconnection request. Any problems identified below are likely to result in operational restrictions to the project under study. The developer can proceed with network upgrades to eliminate the operational restriction at their discretion by submitting a Merchant Transmission Interconnection request.

Note: Only the most severely overloaded conditions are listed below. There is no guarantee of full delivery of energy for this project by fixing only the conditions listed in this section. With a Transmission Interconnection Request, a subsequent analysis will be performed which shall study all overload conditions associated with the overloaded element(s) identified

None.

Attachment 1. Single Line Diagram



Attachment 2. Dynamic Simulation Analysis

TABLE OF CONTENTS

Executive Summary

Generator Interconnection Request AD2-171 (Project AD2-171) is for a 700 MW Maximum Facility Output (MFO) natural gas generating facility. Project AD2-171 consists of one 855 MVA single-shaft generator with a Point of Interconnection (POI) at a new 500 kV switching substation with a three-breaker ring bus configuration. The new 500 kV switching substation, in Hunterdon County, NJ, will be tapped into the 500 kV Public Service Electric & Gas Company (PSE&G) Alburtis-Branchburg Line approximately 28.3 miles from Branchburg 500 kV substation. The AD2-171 generating facility will be connected to the new 500 kV switching substation via approximately 5.0 miles 500 kV line.

This report describes a dynamic simulation analysis of AD2-171 as part of the overall system impact study. The load flow scenario for the analysis was based on the RTEP 2021 light load case, modified to include applicable queue projects. AD2-171 has been dispatched online at maximum power output, with unity power factor and approximately 1.0 pu voltage at the generator terminals.

AD2-171 was tested for compliance with NERC, PJM, Transmission Owner and other applicable criteria. 48 contingencies were studied, each with a 20 second simulation time period (with 1.0 second initial run prior to any events). Studied faults included:

a) Steady state operation (Category P0);

b) Three phase faults with normal clearing time on the intact network (Category P1);

c) Single phase to ground faults with delayed clearing due to a stuck breaker (Category P4);

d) Single phase to ground faults with delayed clearing as a result of protection failure (Category P5);

e) Single phase to ground faults with normal clearing for common structure (Category P7).

For all simulations, the queue project under study along with the rest of the PJM system were required to maintain synchronism and with all states returning to an acceptable new condition following the disturbance.

For all 48 fault contingencies tested on the 2021 light load case:

a) AD2-171 was able to ride through the faults (except for faults where protective action trips a generator(s)).

b) Post-contingency oscillations were positively damped with a damping margin of at least 3%.

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

No mitigations were found to be required for the studied project.

It was found that one of the parameters (CON(J+8)) of the provided turbine-governor model URCSCT was set at 1.33 pu, which limits the power plant maximum generation to about 676 MW. This parameter has been increased to 1.52 pu in this study in order to accommodate the 720 MW power plant output.

It was also found that the 11 MW machine #2 at KEYSTONE (bus#200032) and the 11 MW machine #2 at Conemaugh (bus#200031) showed lower than 3.0% damping ratio under several contingencies. This dynamic response of these two machines was modeled using GENCLS, in other words, no detailed dynamic models are available for these machines. It is recommended to GNET this machine when performing stability analysis. However, as the low damping response is only observed on these two machines. It should not be a concern.

1. Introduction

Generator Interconnection Request AD2-171 (Project AD2-171) is for a 700 MW Maximum Facility Output (MFO) natural gas generating facility. Project AD2-171 consists of one 855 MVA single-shaft generator with a Point of Interconnection (POI) at a new 500 kV switching substation with a three-breaker ring bus configuration. The new 500 kV switching substation, in Hunterdon County, NJ, will be tapped into the 500 kV Public Service Electric & Gas Company (PSE&G) Alburtis-Branchburg Line approximately 28.3 miles from Branchburg 500 kV substation. The AD2-171 generating facility will be connected to the new 500 kV switching substation via approximately 5.0 miles 500 kV line.

This analysis is effectively a screening study to determine whether the addition of AD2-171 will meet the dynamic requirements of the NERC, PJM and Transmission Owner reliability standards.

In this report the AD2-171 project and how it is proposed to be connected to the grid are first described, followed by a description of how the project is modeled in this study. The fault cases are then described and analyzed, and lastly a discussion of the results is provided.

2. Description of Project

Generator Interconnection Request AD2-171 (Project AD2-171) is for a 700 MW Maximum Facility Output (MFO) natural gas generating facility. Project AD2-171 consists of one 855 MVA single-shaft generator with a Point of Interconnection (POI) at a new 500 kV switching substation with a three-breaker ring bus configuration. The new 500 kV switching substation, in Hunterdon County, NJ, will be tapped into the 500 kV PSEG Alburtis-Branchburg Line approximately 28.3 miles from Branchburg 500 kV substation.

The AD2-171 generating facility will be connected to the new 500 kV switching substation via approximately 5.0 miles 500 kV line, as shown in Figure 1.

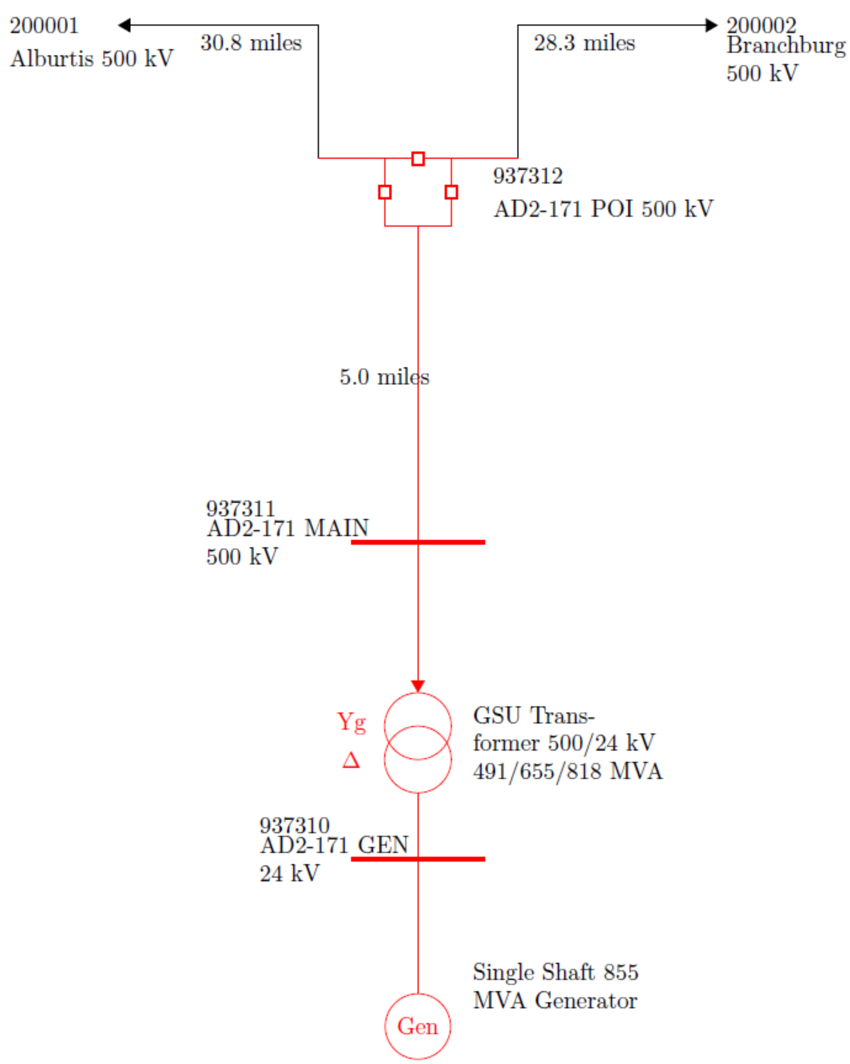


Figure 1: AD2-171 Plant Model

Table 1 lists the parameters given in the impact study data and the corresponding parameters of the AD2-171 loadflow model.

Additional project details are provided in Attachments 1 through 4:

- Attachment 1 contains the Impact Study Data which details the proposed AD2-171 project.
- Attachment 2 shows the one line diagram of the PSE&G and PPL network in the vicinity of AD2-171.
- Attachment 3 provides a diagram of the PSS/E model in the vicinity of AD2-171.
- Attachment 4 gives the AD2-171 PSS/E loadflow and dynamic models of the AD2-171.

Table 1: AD2-171 Plant Model

	Impact Study Data	**Model**
Single Shaft Combined Cycle Generator	1x720 MW generator MVA base = 855 MVA Vt = 24 kV Ra[1] = 0.000750 ohms X"d(i) = 0.220 pu @ MVA base Gross generation = 720 MW Qmax = 330 MVAr Qmin = -237 MVAr	1 x 720 MW generator Pgen 720 MW Pmax 720 MW Pmin 0 MW Qgen -26.86 MVAr Qmax [2]453.15 MVAr Qmin [2]-273.6 MVAr Mbase 855 MVA Zsorce 0.001113+j0.220 pu @ Mbase
GSU transformers	1x 500/24 kV transformer Rating = 491/655/818 MVA (ONAN/ONAF/ONAF2) Transformer base = 491 MVA Impedance = 0.0018 + j0.09 pu @ MVA base Number of taps = 5 Tap step size = 2.5%	1x 500/24 kV two winding transformer (Yng/D) Rating = 491/655/818 MVA Transformer base = 491 MVA Impedance = 0.0018 + j0.09 pu @ MVA base Number of taps = 5 Tap step size = 2.5 %

[1] The Zsource is from the document "Planning Center - Submission Admin - https___queuepoint-internal.ac2prod.pjm.com_.pdf".
[2] The Leading and lagging values are from generator reactive capability curves in the document: "F30-492_GV Model for Single shaft CC_URCSCT and generator curves.pdf".

Transmission Line	5.0 miles 500 kV transmission line Rating = 0 MVA MVA base = 100 MVA Impedance = 0.000438 + j0.001771 pu @ MVA base Charging susceptance = 0.060497 pu @ MVA base	5.0 miles 500 kV transmission line Rating = 0 MVA MVA base = 100 MVA Impedance = 0.000438 + j0.001771 pu @ MVA base Charging susceptance = 0.060497 pu @ MVA base
Auxiliary load and Station Load	Active power = 20 MW Reactive power = 9.7 MVAR	P = 20 MW Q = 9.7 MVAR

During the initial test of the dynamic models, it was found that one of the parameters (CON(J+8)) of the provided turbine-governor model URCSCT was set at 1.33 pu, which limits the power plant maximum generation to about 676 MW. This parameter has been increased to 1.52 pu in this study in order to accommodate the 720 MW power plant output.

3. Reactive Power Assessment

AD2-171 was assessed for compliance with reactive power capability requirements using the supplied capability curves. Please note this is a new facility.

- Generation shall have the ability to maintain a power factor of at least 0.95 leading to 0.90 lagging at generator terminal[3].[4]

Generator	MFO	Required pF Range		Maximum (Lagging)	Minimum (Leading)
		Lagging	Leading		
AD2-171	700	0.90	0.95		
Total MVAR Required				339	-230
MVAR from Generators				Qmax	Qmin
				453.15	-273.6
Customer Planned Compensation				0	0
Qloss				-9.7	-9.7
Total Available MVAR at Generator Terminal				443.45	-283.3
Deficiency in MVAR				Meet	Meet

AD2-171 meets the reactive power requirement at the generator terminal.

[3] As specified in the document "Reactive Power Requirements.doc", Date: 6/15/2018.
[4] As specified in Attachment O of the document "PJM Open Access Transmission Tariff" Effective Date: 4/23/2018.

4. Loadflow and Dynamics Case Setup

The dynamics simulation analysis was carried out using PSS/E Version 33.

The load flow scenario and fault cases for this study are based on PJM's Regional Transmission Planning Process[5].

The selected load flow scenario is the RTEP 2021 light load case with the following modifications:

a) Addition of all applicable queue projects prior to AD2-171.

b) Addition of AD2-171 queue project.

c) Removal of withdrawn and subsequent queue projects in the vicinity of AD2-171.

d) Dispatch of units in the PJM system to maintain slack generators within limits.

The AD2-171 initial conditions are listed in Table 2, indicating maximum power output, with unity power factor and approximately 1.0 pu voltage at the generator terminals. The POI voltage is at 1.05 pu (per the PJM scheduled voltage at 500 kV).

Table 2: AD2-171 machine initial conditions

Bus	Name	Unit	PGEN	QGEN	ETERM	POI Voltage
937302	AD2-171_GEN	1	720 MW	-0.19 MVAR	0.99 pu	1.05 pu

Generation within the vicinity (within five bus away) of AD2-171 has been dispatched online at maximum output (PMAX). The dispatch within the PSE&G area is given in Attachment 5.

[5] Manual 14B: PJM Region Transmission Planning Process, Rev 37, April 28 2017, Attachment G : PJM Stability, Short Circuit, and Special RTEP Practices and Procedures.

5. Fault Cases

Table 5 to Table 9 list the contingencies that were studied, with representative worst case total clearing times provided by PJM. Each contingency was studied over a 20 second simulation time interval (with 1.0 second initial run prior to any events).

The studied contingencies include:

a) Steady state operation (Category P0);

b) Three phase faults with normal clearing time on the intact network (Category P1);

c) Single phase to ground faults with delayed clearing due to a stuck breaker (Category P4);

d) Single phase to ground faults with delayed clearing as a result of protection failure (Category P5);

e) Single phase to ground faults with normal clearing for common structure (Category P7).

High Speed Reclosing (HSR) contingencies at the vicinity of AD2-171 were found[6]:

- 500 kV circuit 5039 (New Freedom to Orchard) recloses with 45 cycles delay.

Buses at which the faults listed above will be applied are:

- AD2-171 POI 500 kV
- Branchburg 500 kV
- Alburtis 500 kV (PPL)
- Deans 500 kV
- New Freedom 500 kV

Table 3 gives the details of fault clearing time 500 kV breakers at PSE&G and PPL[7].

Table 3: 500 kV breaker details

TO	Circuit Breaker	Three Phase Fault Normal Clearing Time (cycles)	SLG Delayed Clearing Time due to Stuck Breaker (cycles)	SLG Delayed Clearing Time due to Primary Relay Failure (cycles)
PSE&G	500 kV	4	16	4/24[8]
PPL	500 kV	3.5	12	24

A complete list of the contingencies that will be studied is given in Table 5 to Table 9.

---

[6] PJM_HighSpeedReclosing_List.xlsx

[7] The conservative value (i.e., longest fault clearing time) in 2017 Revised Clearing time for each PJM company_Rev20.xls is assumed in this study. These values may be checked with TOs if stability issues are observed during the dynamic analysis.

[8] For 500 kV line 5016 and 5017, the delayed clearing time is 24 cycles. For all other lines are 4 cycles according to “2017 Revised Clearing time for each PJM company_Rev20.xls”.

The positive sequence fault impedances for single line to ground faults were derived through the procedure described in *SLG fault equivalent impedance estimation for stability study,* dated 02/10/17.

6. Evaluation Criteria

This study is focused on AD2-171, along with the rest of the PJM system, maintaining synchronism and having all states return to an acceptable new condition following the disturbance. The recovery criteria applicable to this study are as per PJM's Regional Transmission Planning Process and Transmission Owner criteria:

a) AD2-171 is able to ride through the faults (except for faults where protective action trips a generator(s)),

b) The system with AD2-171 included is transiently stable and post-contingency oscillations should be positively damped with a damping margin of at least 3%.

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

7. Summary of Results

Plots from the dynamic simulations are provided in Attachment 6, with results summarized in Table 5 through Table 9.

For all 48 of the fault contingencies tested on the 2021 light load case:

a) AD2-171 was able to ride through the faults (except for faults where protective action trips a generator(s)).

b) Post-contingency oscillations were positively damped with a damping margin of at least 3%.

c) Following fault clearing, all bus voltages recover to a minimum of 0.7 per unit after 2.5 seconds (except where protective action isolates that bus).

d) No transmission element trips, other than those either directly connected or designed to trip as a consequence of that fault.

No mitigations were found to be required.

It was found that one of the parameters (CON(J+8)) of the provided turbine-governor model URCSCT was set at 1.33 pu, which limits the power plant maximum generation to about 676 MW. This parameter has been increased to 1.52 pu in this study in order to accommodate the 720 MW power plant output.

It was also found that the 11 MW machine #2 at KEYSTONE (bus#200032) and the 11 MW machine #2 at Conemaugh (bus#200031) showed lower than 3.0% damping ratio under several contingencies. This dynamic response of these two machines was modeled using GENCLS, in other words, no detailed dynamic models are available for these machines. It is recommended to GNET this machine when performing stability analysis. However, as the low damping response is only observed on these two machines. It should not be a concern. The damping ratios calculated for the active power of this machine are shown below.

Table 4: Damping Ratio – Active Power of Machine #2 at KEYSTONE (Bus#200032) and of Machine #2 at Conemaugh (Bus#200031)

Fault ID	POWR200031[CONE G2 22.000]2		POWR200032[KEYS G1 20.000]2	
	Dominant Frequency (Hz)	Damping Ratio (%)	Dominant Frequency (Hz)	Damping Ratio (%)
P1_01	1.25	3.27	1.27	3.56
P1_02	1.25	3.54	1.26	2.54
P1_03	1.25	3.40	1.27	1.77
P1_04	1.25	3.30	1.26	3.45
P1_05	1.25	3.14	1.24	2.39
P1_06	1.25	3.33	1.22	2.12
P1_07	1.25	3.30	1.25	2.08
P1_08	1.25	3.40	1.24	1.64
P1_09	1.25	3.40	1.24	1.64
P1_10	1.23	4.63	1.25	3.49
P1_11	1.24	4.88	1.24	4.10

Fault ID	POWR200031[CONE G2 22.000]2		POWR200032[KEYS G1 20.000]2	
	Dominant Frequency (Hz)	Damping Ratio (%)	Dominant Frequency (Hz)	Damping Ratio (%)
P1_12	1.24	4.38	1.24	4.66
P1_13	1.23	4.31	1.24	5.57
P1_14	1.23	4.30	1.25	4.04
P1_15	1.26	4.58	1.25	5.65
P1_16	1.25	3.27	1.27	6.09
P1_17	1.26	3.49	1.26	5.49
P1_18	1.24	2.25	1.23	2.84
P1_19	1.24	2.83	1.24	3.13
P1_20	1.27	0.52	1.25	3.07
P1_21	1.24	2.25	1.23	2.84
P1_22	1.24	2.60	1.23	7.85
P1_23	1.23	4.33	1.24	4.81
P4_1B1_01	1.26	1.60	1.26	5.84
P4_1B1_02	1.26	3.86	1.29	5.25
P4_1B1_03	1.25	3.37	1.27	5.42
P4_1B1_04	1.26	3.75	1.22	4.23
P4_1B1_05	1.25	3.34	1.25	4.64
P4_1B1_06	1.25	3.34	1.25	4.64
P4_1B1_07	1.25	3.67	1.25	5.18
P4_1B1_08	1.25	3.01	1.24	4.51
P4_1B1_09	1.27	2.24	1.24	4.48
P4_1B1_10	1.26	4.08	1.26	2.93
P4_1B1_11	1.23	4.32	1.26	3.55
P4_1B1_12	1.25	3.86	1.27	2.92
P4_1B1_13	1.24	4.04	1.23	4.28
P4_1B1_14	1.21	4.06	1.24	2.94
P4_1B1_15	1.27	4.37	1.22	6.30
P4_1B1_16	1.24	4.02	1.26	3.51
P5_01	1.20	5.61	1.24	7.96
P5_02	1.25	2.77	1.23	0.10
P5_03	1.26	3.57	1.24	6.30
P5_04	1.26	3.50	1.26	4.21
P5_05	1.25	4.38	1.26	4.59

Fault ID	POWR200031[CONE G2 22.000]2		POWR200032[KEYS G1 20.000]2	
	Dominant Frequency (Hz)	Damping Ratio (%)	Dominant Frequency (Hz)	Damping Ratio (%)
P5_06	1.25	3.59	1.31	1.72
P5_07	1.25	3.35	1.35	4.25
P7_01	1.25	3.95	1.26	2.92

Table 5: Steady State Operation – Category P0

Fault ID	Duration	AD2-171 No Mitigation
P0_01	Steady state 20 sec	Stable

Table 6: Three-phase Faults with Normal Clearing – Category P1

Fault ID	Fault description	Clearing Time & Reclose (Cycles)	AD2-171 No Mitigation
P1.01	3ph fault @ AD2-171 POI 500 kV on Branchburg, normal clear loss of AD2-171 – Branchburg circuit 5016	4	Stable
P1.02	3ph fault @ AD2-171 POI 500 kV on Alburst, normal clear loss of AD2-171 – Alburst circuit 5016	4	Stable
P1.03	3ph fault @ Branchburg 500 kV on AD2-171 circuit 5016, normal clear loss of BRAN-AD2-171 circuit 5016	4	Stable
P1.04	3ph fault @ Branchburg 500 kV on DEAN circuit 5019, normal clear loss of BRAN-DEAN circuit 5019	4	Stable
P1.05	3ph fault @ Branchburg 500 kV on HOPA circuit 5060, normal clear loss of BRAN-HOPA circuit 5060	4	Stable
P1.06	3ph fault @ Branchburg 500 kV on ELRO circuit 5017, normal clear loss of BRAN-ELRO circuit 5017	4	Stable
P1.07	3ph fault @ Branchburg 500 kV on TF#1, normal clear loss of TF#1	4	Stable
P1.08	3ph fault @ Branchburg 500 kV on TF#2, normal clear loss of TF#2	4	Stable
P1.09	3ph fault @ Branchburg 500 kV on TF#3, normal clear loss of TF#3	4	Stable
P1.10	3ph fault @ Alburtis 500 kV on AD2-171 circuit 5016, normal clear loss of ALBU-AD2-171 circuit 5016	3.5	Stable
P1.11	3ph fault @ Alburtis 500 kV on HOSE circuit 5027, normal clear loss of ALBU-HOSE circuit 5027	3.5	Stable
P1.12	3ph fault @ Alburtis 500 kV on JUNI circuit 5009, normal clear loss of ALBU-JUNI circuit 5009	3.5	Stable
P1.13	3ph fault @ Alburtis 500 kV on BREI circuit BREI-ALBU 2, normal clear loss of ALBU-BREI circuit BREI-ALBU 2	3.5	Stable
P1.14	3ph fault @ Alburtis 500 kV on TF#1, normal clear loss of TF#1	3.5	Stable
P1.15	3ph fault @ Deans 500 kV on BRAN circuit 5019, normal clear loss of BRAN-DEAN circuit 5019	4	Stable
P1.16	3ph fault @ Deans 500kV on East Windsor circuit 5022, normal clear loss of Deans – East Windsor circuit 5022	4	Stable

Fault ID	Fault description	Clearing Time & Reclose (Cycles)	AD2-171 No Mitigation
P1.17	3ph fault @ Deans 500 kV on Smithburg circuit 5020, normal clear loss of Deans – Smithburg circuit 5020	4	Stable
P1.18	3ph fault @ New Freedom 500 kV on East Windsor circuit 5038, normal clear loss of New Freedom – East Windsor circuit 5038	4	Stable
P1.19	3ph fault @ New Freedom 500 kV on Salem circuit 5024, normal clear loss of New Freedom – Salem circuit 5024	4	Stable
P1.20	3ph fault @ New Freedom 500 kV on Orchard circuit 5039, normal clear loss of New Freedom – Orchard circuit 5039	4/45	Stable
P1.21	3ph fault @ New Freedom 500 kV on Hope Creek circuit 5023, normal clear loss of New Freedom – Hope Creek circuit 5023	4	Stable
P1.22	3ph fault @ New Freedom 500 kV, normal clear loss of New Freedom SVC	4	Stable
P1.23	3ph fault @ Alburtis 500 kV on BREI circuit BREI-ALBU 1, normal clear loss of BREI-ALBU 1	3.5	Stable

Table 7: Single-phase Faults With Stuck Breaker (Single-Phase Delayed Fault Clear) – Category P4

Fault ID	Fault description	Clearing Time Normal and Delayed (Cycles)	AD2-171 No Mitigation
P4_1B1.01	SLG @ AD2-171 POI 500 kV, normal clear loss of AD2-171 – Branchburg circuit 5016, SB @ AD2-171 500kV, delayed clear loss of AD2-171 – Alburtis circuit 5016, AD2-171	4/16	Stable
P4_1B1.02	SLG @ AD2-171 POI 500 kV, normal clear loss of Alburtis – AD2-171 circuit 5016, SB @ AD2-171 POI 500 kV, delayed clear loss of AD2-171 – Branchburg circuit 5016, AD2-171	4/16	Stable
P4_1B1.03	SLG @ Branchburg 500 kV, normal clear loss of Branchburg – HOPA circuit 5060, SB 14-8 @ Branchburg 500 kV, delayed clear loss of 200 MVar capacitor	4/16	Stable
P4_1B1.04	SLG @ Branchburg 500 kV, normal clear loss of Branchburg – Elroy circuit 5017, SB 5-6 @ Branchburg 500 kV, delayed clear loss of TF #3	4/16	Stable
P4_1B1.05	SLG @ Branchburg 500 kV, normal clear loss of Branchburg – Deans circuit 5019, SB 4-5 @ Branchburg 500 kV, delayed clear loss of TF#3	4/16	Stable
P4_1B1.06	SLG @ Branchburg 500 kV, normal clear loss of Branchburg – Deans circuit 5019, SB 4-3 @ Branchburg 500 kV, delayed clear loss of TF#2	4/16	Stable
P4_1B1.07	SLG @ Branchburg 500 kV, normal clear loss of Branchburg 500/230 kV TF#1, SB @ Branchburg 500 kV TF#1 breaker, delayed clear with no additional element loss	4/16	Stable
P4_1B1.08	SLG @ Alburtis 500 kV, normal clear loss of Alburtis – JUNI circuit 5009, SB @ Alburtis 500 kV bus, delayed clear loss of 500/230 kV TF#1	3.5/12	Stable
P4_1B1.09	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - JUNI circuit 5009, SB @ Alburtis 500 kV bus, delayed clear loss of ALBU – HOSE circuit 5027	3.5/12	Stable
P4_1B1.10	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - BREI circuit 2, SB @ Alburtis 500 kV, delayed clear loss of ALBU – AD2-171 circuit 5016	3.5/12	Stable
P4_1B1.11	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - BREI circuit 2, SB @ Alburtis 500 kV, delayed clear loss of 500/230 kV TF#1	3.5/12	Stable
P4_1B1.12	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - BREI circuit 1, SB @ Alburtis 500 kV, delayed clear loss of Reactor 1, Capacitor 1 & 2	3.5/12	Stable
P4_1B1.13	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - HOSE circuit 5027, SB @ Alburtis 500 kV, delayed clear loss of ALBU – JUNI circuit 5009	3.5/12	Stable
P4_1B1.14	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - HOSE circuit 5027, SB @ Alburtis 500 kV, delayed clear loss of Reactor 1, Capacitor 1 & 2	3.5/12	Stable
P4_1B1.15	SLG @ Deans 500 kV, normal clear loss of Deans 500/230 kV TF#1, SB 3-4 @ Deans 500 kV	4/16	Stable

Fault ID	Fault description	Clearing Time Normal and Delayed (Cycles)	AD2-171 No Mitigation
	bus, delayed clear loss of Deans – Branchburg circuit 5019		
P4_1B1.16	SLG @ Alburtis 500 kV, normal clear loss of Alburtis - BREI circuit 1, SB @ Alburtis 500 kV, delayed clear loss of 500/230 kV TF#1	3.5/12	Stable

Table 8: Single-phase Faults with Delayed (Zone 2) Clearing due to Primary Communication/Relay Failure – Category P5

Fault ID	Fault description	Clearing Time (Cycles)	AD2-171 No Mitigation
P5.01	SLG fault @ 80% of AD2-171 – Branchburg 500 kV circuit 5016, delayed clearing	4/24	Stable
P5.02	SLG fault @ 80% of AD2-171 – Alburtis 500 kV circuit 5016, delayed clearing	4/24	Stable
P5.03	SLG fault @ 80% of Branchburg – ELRO 500 kV circuit 5017, delayed clearing	4/24	Stable
P5.04	SLG fault @ 80% of ALBU – HOSE 500 kV circuit 5027, delayed clearing	3.5/24	Stable
P5.05	SLG fault @ 80% of ALBU – JUNI 500 kV circuit 5009, delayed clearing	3.5/24	Stable
P5.06	SLG fault @ 80% of ALBU – BREI 500 kV circuit 2, delayed clearing	3.5/24	Stable
P5.07	SLG fault @ 80% of ALBU – BREI 500 kV circuit 1, delayed clearing	3.5/24	Stable

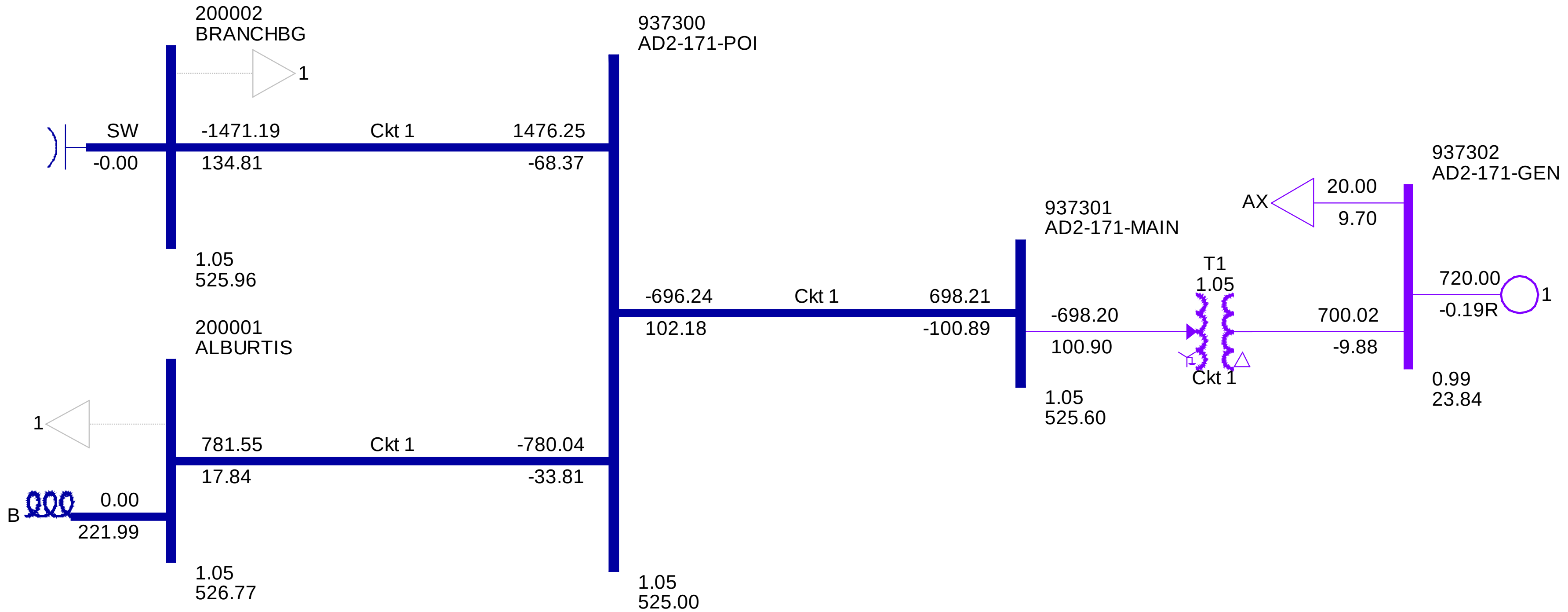
Table 9: Single Phase Faults with Normal Clearing on Common Structure – Category P7

Fault ID	Fault description	Clearing Time (Cycles)	AD2-171 No Mitigation
P7.01	CONTINGENCY 'PL:P71:001322' SLG fault @ Alburtis 500 kV on BREI 500 kV line, tower failure normal clearing loss of ALBU – BREI 500 kV lines	3.5	Stable

Attachment 1. Impact Study Data

Attachment 2. PSE&G and PPL One Line Diagram

Attachment 3. PSS/E Model One Line Diagram



Attachment 4. AD2-171 PSS/E Dynamic Model

```
/*************************************************
/*** AD1-171 - 700 MW MFO
/*** POI on Alburtis - Branchburg 500 kV
/**************************************************


/***********************************************************************************************
/ PSSE Version 33
/***********************************************************************************************
/ CON(J+8) of URCSCT needs to be increased to 1.52
 937302 'GENROU' 1     8.000      0.50000E-01  1.0000      0.8000E-01
        4.630     0.0200      2.4100      2.4100     0.26000
       0.44000     0.22000     0.15000     0.11000     0.5900    /
 937302 'URCSCT' 1
        25.000       0.000      0.0500      1.0000     0.04
          0.17       374.9      0.0500      1.5200     0.00
        0.0100      0.7070      1.0000     0.20000     1.0000
        0.2000     0.00000      0.2000     0.80000     15.000
        15.000     6400.00      24.000      0.1490     0.4010
       -0.2490     1.24900      0.1000      0.9870     0.2930
        1.0000
        25.000     0.10000      0.0000      0.0500     3.4   -3.4
        1.0000     0.00000      0.3000      0.2600     0.0    6.6
        0.3600     0.00000      0.2500      0.3800     0.0    0.0
        0.0        0.0
        177.5      305.7        98.2        427.5      137.3
        487.3      156.5  /
 937302 'ESST1A' 1    3   1
        0.0130     99.0000    -99.0000      0.0000     0.0
        0.2000     0.50000      440.00      0.0000     99.0
       -99.000     5.80000     -4.7000      0.2050     0.00
        1.0000      0.0000       0.0   /
 937302 'PSS2B' 1    2   0    3   0   5   1
        2.0000     2.00000      0.0000      2.0000     0.0    2.0
```

```
      0.2000     1.00000     0.0000     0.1000    3.0   0.2
      0.0400     0.36000     0.1200     0.0100    0.01  99.0
      -99.00    99.0000    -99.000     0.1       -0.1   /
*******************************************************************************************
```

Attachment 5. AD2-171 PSS/E Case Dispatch

Bus Number	Bus Name	Id	VSched (pu)	Remote Bus Number	In Service	PGen (MW)	PMax (MW)	PMin (MW)	QGen (Mvar)	QMax (Mvar)	QMin (Mvar)	Mbase (MVA)
200030	CONE G1 22.000	H	1.052	200005	1	455.4	455.4	262	36.853	175.23	-7.85	545
200030	CONE G1 22.000	L	1.052	200005	1	415.2	415.2	238	33.5999	159.77	-7.15	495
200031	CONE G2 22.000	2	1.052	200005	1	11	11	0	0	0	0	100
200031	CONE G2 22.000	H	1.052	200005	1	455.4	455.4	262	36.8784	136.097	13.09	545
200031	CONE G2 22.000	L	1.052	200005	1	414.6	414.6	238	33.5744	123.903	11.91	495
200032	KEYS G1 20.000	2	1.052	200011	1	11	11	0	1	1	0	100
200032	KEYS G1 20.000	H	1.052	200011	1	435	435	254.5	61.3884	183.5	0	481
200032	KEYS G1 20.000	L	1.052	200011	1	418.4	418.4	245.5	59.0458	176.5	0	464
200033	KEYS G2 20.000	H	1.052	200011	1	435	435	254.5	61.8981	183.5	0	481
200033	KEYS G2 20.000	L	1.052	200011	1	418.4	418.4	245.5	59.536	176.5	0	464
200036	SALEM-G1 22.000	1	1.05	200014	1	1253	1253	1090.11	219.9953	535	100	1300
200037	SALEM-G2 22.000	1	1.05	200014	1	1245	1245	1083.15	219.9953	544.11	100	1300
200038	SUSQ 2 24.000	2	1.07	200022	1	1304	1304	1096.2	211.3009	425.654	0	1354
200039	HOPE CG1 22.000	1	1.05	200029	1	1320	1320	0	303.6205	560	108	1373
200044	BETH CT1 13.800	1	1.07	200043	1	118	118	80	15	15	-26	144
200045	BETH CT2 13.800	1	1.07	200043	1	127	127	80	15	15	-5	144
200046	BETH CT3 13.800	1	1.07	200043	1	127	127	80	15	15	-5	144
200047	BETH CC4 18.000	1	1.07	200043	1	195	195	50	87.769	87.769	-27.615	230
200048	BETH CT5 13.800	1	1.07	200043	1	118	118	80	7.1	7.1	-12.1	144
200049	BETH CT6 13.800	1	1.07	200043	1	127	127	80	16	16	-5	144
200050	BETH CT7 13.800	A	1.07	200043	1	127	127	80	15	15	-5	144
200062	SALEM G3 22.000	1	1.05	200014	1	38.4	38.4	0	14	14	-14	100
200101	NEWFRDM_SVC 500.00	1	1.05	0	1	0	0	0	-10.5036	300	-150	100
204659	27TMI 1GEN 19.000	1	1.0217	204514	1	860.7	860.7	79.5	-103.3	376.7	-103.3	1037.9
208918	SUSQ 1 24.000	1	1.0304	208113	1	1304	1304	1096.2	0	369.115	0	1354

Bus Number	Bus Name	Id	VSched (pu)	Remote Bus Number	In Service	PGen (MW)	PMax (MW)	PMin (MW)	QGen (Mvar)	QMax (Mvar)	QMin (Mvar)	Mbase (MVA)
208980	BEPO IPP 18.000	1	1.0196	208101	1	195	195	50	-20.2738	105	-35	230
218379	BRUNSWCK_AB 26.400	1	1.03	0	1	9	9	0	7	7	-5	10
235619	AD2-113 G1 18.000	1	1.05	235118	1	100	199.3	0	-50	100	-50	234
235620	AD2-113 G2 18.000	1	1.05	235118	1	100	199.3	0	-50	100	-50	234
235621	AD2-113 G3 18.000	1	1.05	235118	1	100	199.3	0	-50	100	-50	234
235622	AD2-113 G4 18.000	1	1.05	235118	1	100	199.3	0	-50	100	-50	234
292112	V1-030 CA 230.00	1	1.0217	0	1	2.926	2.926	0	1.404	1.404	-0.966	100
292189	V1-030 EA 230.00	1	1.0217	0	1	4.774	4.774	0	2.292	2.292	-1.575	100
292666	V3-058 E 230.00	1	1.0109	0	1	2	2	0	0	0	0	100
292668	V3-059 E 230.00	1	1.0109	0	1	2	2	0	0	0	0	100
902491	W2-036C 13.000	1	1.003	0	1	0.3	0.3	0	0	0	0	100
920651	AA2-171 CT1 18.000	1	1.07	200021	1	243.7	243.7	0	80.0352	120	-96	272
920652	AA2-171 CT2 18.000	1	1.07	200021	1	243.7	243.7	0	80.0352	120	-96	272
920653	AA2-171 CT3 18.000	1	1.07	200021	1	243.7	243.7	0	80.0352	120	-96	272
920654	AA2-171 ST 22.000	1	1.07	200021	1	421	421	0	80.0352	259	-220	541
920717	AB2-074 GEN123.500	1	1.07	200021	1	585	585	0	80.0352	283.14	-192.465	661
920718	AB2-074 GEN223.500	1	1.07	200021	1	585	585	0	80.0352	283.14	-192.465	661
936192	AD2-025 E 13.200	1	1.04	0	1	2	2	0	0.66	0.66	-0.66	100
936901	AD2-114 G1 24.000	1	1.05	235118	1	200	410	0	-130	200	-130	480
937302	AD2-171-GEN 24.000	1	1.05	937300	1	720	720	0	-0.1851	453.15	-273.6	855