GENERATOR INTERCONNECTION

FEASIBILITY STUDY

for integration of the proposed

80 MW [redacted] PROJECT

(GI PROJECT #434)

to the

IDAHO POWER COMPANY ELECTRICAL SYSTEM

in

ADA COUNTY, IDAHO

for

[redacted]

FINAL REPORT

October 29, 2014

Revision History

Date	Revision	Initials	Summary of Changes
10/10/2014	0	MDH	FeSR GI Project #434 – Issued Preliminary Report
10/14/2014	1	MDH	FeSR GI Project #434 – Issued Report for Interconnection Customer review and comment
10/29/2014	2	MDH	FeSR GI Project #434 – Updated Report to Include Interconnection Customer's comments

Table of Contents

1.0 Introduction

[redacted] has contracted with Idaho Power Company (IPCo) to perform a Generator Interconnection Feasibility Study for the integration of the proposed 80 MW [redacted] Project (GI Project #434). The location of the project is in Idaho Power's Capital Region in Ada County, Idaho.

The specific point of interconnection studied is a proposed new 138kV tap on the existing IPCo owned line between the [redacted] Substations. The proposed interconnection tap would be located approximately 6.1 miles from the [redacted] Station between [redacted] Tap.

This report documents the basis for, and the results of, this Feasibility Study for the Generation Interconnection Customer. It describes the proposed project, the determination of project interconnection feasibility, and estimated costs for integration of the Project to the Idaho Power Transmission System at 138kV.

2.0 Summary

The feasibility of interconnecting the 80 MW solar generation project to Idaho Power's [redacted] 138 kV line was evaluated.

Power flow analysis indicated that interconnecting the [redacted] Project (GI Project #434) is feasible. Identification of transmission system network upgrade requirements and transmission service requirements to interconnect the 80 MW Project to the IPCo System were not evaluated in this Feasibility Study. Also noted was that GI Project #434 will not meet the power factor requirements required by IPCo. By adding a 5.2 MVAR switched shunt capacitor to the Interconnection Customer's 34.5 kV bus, all power factor requirements can be met. The project will also have to meet the voltage schedule provided by Idaho Power.

A Transmission System Impact Study is required to determine if any additional network upgrades are required to integrate this project into the IPCo transmission system and to evaluate system impacts (thermal, voltage, transient stability, reactive margin). Generator interconnection service (either as an Energy Resource or a Network Resource) does not in any way convey any right to deliver electricity to any specific customer or point of delivery. Transmission requirements to integrate this project will be determined during the System Impact Study phase of the generator interconnection process.

The Project's projected Commercial Operating Date (COD) is [redacted] And, the Generation Interconnection Customer is also requesting an In-Service date of [redacted] and a "First Synch" date of [redacted] The Project's scheduled In-Service date will be based/determined upon the design and construction scheduled outlined in the Facility Study Report for the Project.

The total preliminary cost estimate to interconnect the GI Project #434 Solar Project to Idaho Power's 138 kV system between [redacted] Tap is $2,181,600. Assumes an OPWG shield wire will be installed on the new 2.5 mile 138kV tap line by the generation project.

The cost estimate includes direct equipment and installation labor costs, indirect labor costs and general overheads, and a contingency allowance. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. It should be noted that the preliminary cost estimate of $2,181,600 does not include the cost of the customer's equipment to construct the solar generation site or any Network Upgrades necessary to meet additional requirements that may be identified in the System Impact Study.

3.0 Scope of Interconnection Feasibility Study

The Interconnection Feasibility Study was done and prepared in accordance with Idaho Power Company Standard Generator Interconnection Procedures, to provide a preliminary evaluation of the feasibility of the interconnection of the proposed generating project to the Idaho Power system. As listed in the Interconnection Feasibility Study agreement, the Interconnection Feasibility Study report provides the following information:

- Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
- Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;
- Initial review of grounding requirements and electrical system protection; and
- Description and non-binding estimated cost of facilities required to interconnect the Small Generating Facility to the IPCo System and to address the identified short circuit and power flow issues.

All other proposed Generation projects prior to this project in the Generator Interconnect queue were considered in this study. A current list of these projects can be found in the Generation Interconnection folder located on the Idaho Power web site at the link shown below:

http://www.oatioasis.com/ipco/index.html.

4.0 Description of Proposed Generating Project

GI Project #434 proposes to connect to the Idaho Power transmission system at 138kV with a total injection of 80 MW (maximum project output). The proposed interconnection is via a 2.5 mile (approximate) 138kV tap line from the project's 138/34.5kV generation station to the proposed tap location on the [redacted] 138kV line. The 138kV tap line is to be owned by the generation project.

The Project's projected Commercial Operating Date (COD) is [redacted] And, the Generation Interconnection Customer is also requesting an In-Service date of [redacted] and a "First Synch" date of [redacted] The Project's scheduled In-Service date will be based/determined upon the design and construction scheduled outlined in the Facility Study Report for the Project.

5.0 Description of Transmission Facilities

All generation projects in the area ahead of this project in the IPCo generation queue and their associated transmission system improvements were modeled in a preliminary power flow analysis to evaluate the feasibility of interconnecting GI Project #434.

Preliminary power flow analysis indicated that interconnection of a 80 MW injection at the POI considered in this study is feasible; however, identification of transmission system upgrade requirements and transmission service requirements to interconnect the 80 MW Project to the IPCo System as a Network Resource were not evaluated in this Feasibility Study. A transmission system impact study will be required to determine the specific network upgrades required and available transmission capacity to integrate the full project output of 80 MW.

6.0 Description of Interconnection Facilities

Integration of GI Project #434 will require the construction of a new 138kV substation at the [redacted] generation substation, the addition of an OPWG shield wire to the existing 138kV line, and a short 138kV transmission line stub at the tap location.

The new 138kV [redacted] generation interconnection includes: New 101A generator/line breaker and free-standing air-breaks installed. (1) New [redacted] line relaying package installed using digital communications. New 120' X 120' fenced yard with (2) 30' gates, pre-fabricated control building with AC & DC systems installed. Conduits run between all yard apparatus/equipment and the control building. 138kV Revenue metering package installed. TeleComm activation fee, cable and SNC protection added for POTS line, SCADA, relay maintenance and Rev Mtg comm's. Satellite clock and antenna installed. Local service to the station is provided by customer to this site.

The actual station layout and detailed equipment requirements will be determined in the Facility Study should the interconnection customer choose to move to that study phase of the interconnection process.

Digital communication from [redacted] to the [redacted] generation station: An existing shield wire on the [redacted] to the proposed interconnection tap line segment (approximately six miles) will be replaced with an OPWG shield wire. It is assumed the generation project will construct the new 138kV tap line with an OPWG shield wire (≈ $110K adder). And, fiber terminal equipment will be installed at both the [redacted] and [redacted] generation interconnection stations.

The new 138kV transmission line stub will consist of a new tap structure and two transition structures in the existing 138kV line with a single span from the tap structure to a new air-break switch and structure (point of demarcation).

Figure 1 shows an area one-line for interconnection of this project.

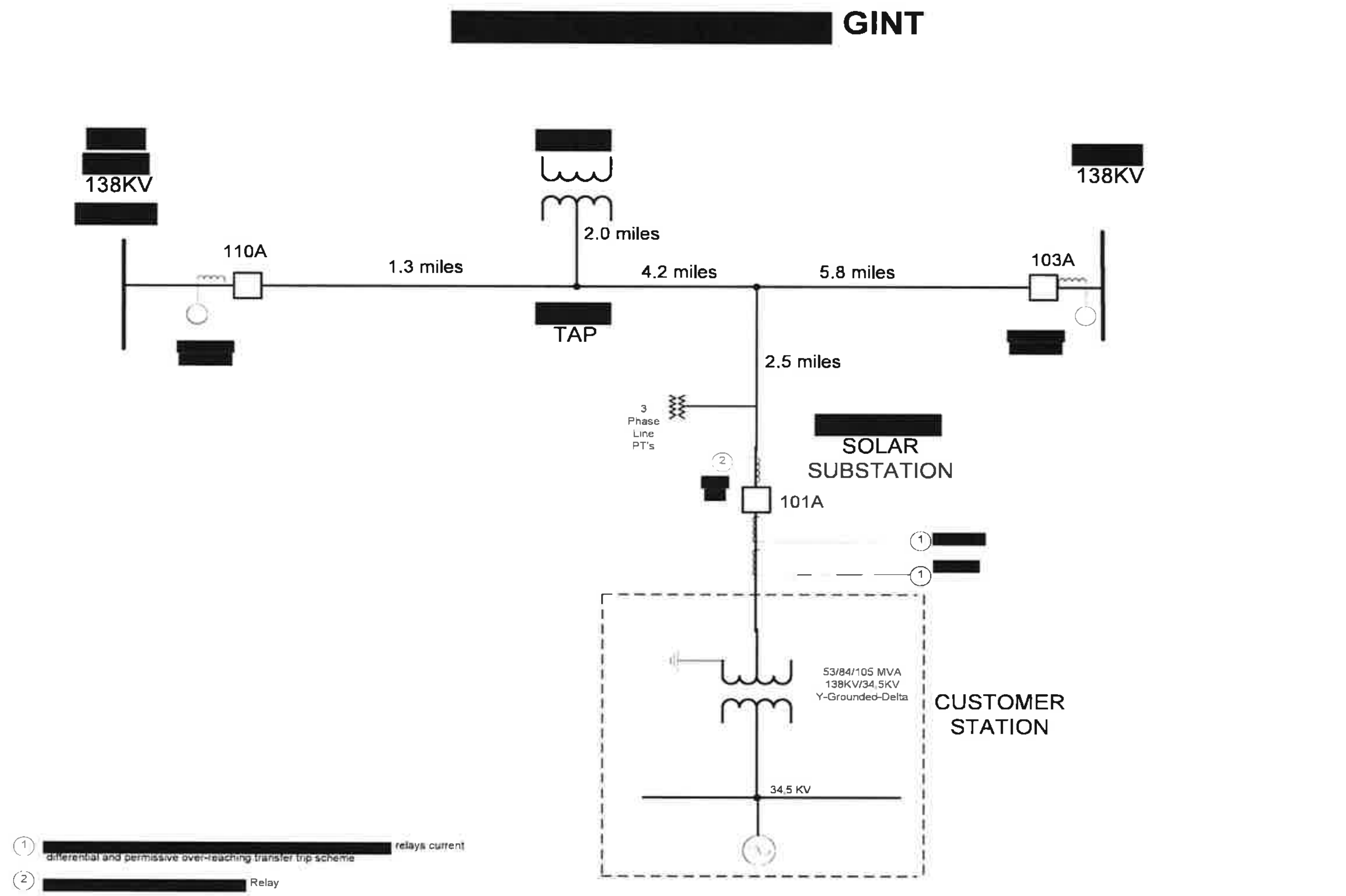

Figure 1: IPCo Area One-Line

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7.0 Short Circuit Study Results

Fault current contribution: the rated fault current contribution from GI Project #434 (as per the interconnection request) is rated at 1.00 pu. of full load current. For an 88 MVA array this would equal 1473 amps at 34.5kV, and 368 amps at 138kV. IPCo does not anticipate that the fault current contribution will exceed any existing circuit breaker interrupter ratings.

Fault current contributions from the IPCo system to the [redacted] buses are as follows:
Single line-to-ground (SLG) fault on the 138kV bus = 7900 amps, 3 phase fault on the 138kV bus = 11900 amps
Single line-to-ground (SLG) fault on the 34.5kV bus – Not Applicable, 3 phase fault on the 34.5kV bus = 8180 amps
Note: With the delta connection on the 34.5kV side of the GINT main 138/34.5kV transformer, there will be no fault contribution from the IPCo system for a SLG fault on the 34.5kV bus.

A more comprehensive study will be conducted during the System Impact Study should the interconnection customer choose to proceed to that study phase of the interconnection process.

8.0 Grounding Requirements and Electric System Protection Results

The proposed ([redacted]) customer owned wye-grounded/delta 138kV/34.5kV substation transformer meets Idaho Power's transmission interconnection grounding requirements. If a wye-grounded connection is required for the 34.5kV winding then it is recommended a wye-grounded/wye-grounded with a delta tertiary transformer be installed.

The 43/47 year old terminal relaying at the [redacted] and [redacted] are scheduled to be replace with our typical [redacted] line protection package integrated with our existing digital communication infrastructure to provide permissive and line differential protection. Because of the scheduled terminal protection upgrades on the [redacted] 138kV line, digital communication will be required at the [redacted] generation substation for its 138kV line terminal.

9.0 Description of Power Flow Cases

The WECC 2014 HS4-OP operating case, approved November 7, 2013 was chosen as the initial power flow basecase for this feasibility study. This power flow base case was modified by IPCo's System Planning Department to represent 2016 summer peak loading conditions on transmission elements near the proposed POI and to include IPCo transmission projects which will be constructed / completed prior to project integration. Next, the base case was modified to include network upgrades assigned to projects ahead of GI Project #434 in the generation interconnection queue.

This case was built to provide a baseline of thermal flows and voltages in the IPCo area prior to adding the generation injection of 80 MW from GI Project #434. This power flow case is referred to as 16hs_IPCm [redacted] pre project) in this study.

A second power flow case, referred to as 16hs_IPCm_[redacted], was then developed from the [redacted] pre-project case to include the GI Project #434 80 MW PV generator and collector system equivalents to represent the Project based on the best available data at the time of this Feasibility Study.

10.0 Post-Transient Analysis

A post-transient analysis was performed on 16hs_IPCm (Pre-GI #434) and 16hs_IPCm_[redacted] (Post-GI #434) to identify if any thermal overload or voltage limit violations result from the interconnection of the 80 MW maximum project output.

Pre-project studies indicate all elements are less than or equal to the continuous rating (100%) of the element for N-0 conditions and all voltages are within criteria in the area of interest. Post-project studies indicate that the 80 MW generation injection to the Idaho Power transmission system from GI Project #434 does not cause any existing system elements to exceed their continuous thermal or voltage ratings for N-0 conditions in the area of interest.

Pre-project contingency studies using the 16hs_IPCm (Pre-GI #434) case indicates no elements are overloaded above their emergency rating and that there are no voltage violations or voltage deviation violations in the area of interest. Post-project contingency studies using the 16hs_IPCm_[redacted] (Post-GI #434) case indicate no elements are overloaded above their emergency rating and that there are no voltage violations or voltage deviation violations in the area interest as a result of adding GI Project #434.

11.0 Transient Stability Analysis

A very limited transient stability analysis has been performed to date. The analysis has been confined to inputting the provided data for the five models (regc_a, reec_b, repc_a, lhvrt, and lhfrt) and testing the data below.

```
# Models for 80 MW [redacted] Project
regc_a  60430 '[redacted]  "  0.80  "1 " : #2 mva=88.00 "lvplsw" 1.0 "rrpwr" 1.000000 "brkpt" 0.8000000
"zerox" 0.400000 "lvpl1" 1.000000 "vtmax" 1.200000 "lvpnt1" 1.000000 "lvpnt0" 0.000000 "qmin" -0.417000
"accel" 0.000000 "tg" 0.008000 "tfltr" 0.020000 "iqrmax" 1.000000 "iqrmin" -1.000000 "xe" 0.000000
reec_b  60430 '[redacted]  "  0.80  "1 " : #9 "mvab" 88.00 "vdip" 0.800000 "vup" 1.200000 "trv" 0.016668
"dbd1" -999.000 "dbd2" 0.100000 "kqv" 1.111000 "iqh1" 0.456500 "iql1" -0.456500 "vref0" 1.000000
"tp" 0.016668 "qmax" 0.417000 "qmin" -0.417000 "vmax" 1.200000 "vmin" 0.800000 "kqp" 0.0000000
"kqi" 0.000000 "kvp" 0.000000 "kvi" 0.000000 "tiq" 0.016668 "dpmax" 1.000000 "dpmin" -1.000000
"pmax" 0.910000 "pmin" 0.000000 "imax" 1.000000 "tpord" 0.016668 "pfflag" 0.0 "vflag" 1.0 "qflag" 0.0
"pqflag" 0.0
repc_a  60430 '[redacted]  "  0.80  "1 " 60428 '[redacted]  "  34.50 : #9 "mvab" 88.00 "tfltr" 0.200000
"kp" 18.000000 "ki" 5.000000  "tft" 0.000000 "tfv" 0.150000 "refflg" 1.000000 "vfrz" -1.000000 "rc" 0.000000
```

```
"xc" 0.000000 "kc" 0.000000 "vcmpflg" 1.000000 "emax" 999.00 "emin" -999.00 "dbd" 0.00 "qmax" 0.417000
"qmin" -0.417000 "kpg" 0.100000 "kig" 0.500000 "tp" 0.250000 "fdbd1" 0.000000 "fdbd2" 0.000000
"femax" 999.00 "femin" -999.00 "pmax" 999.00 "pmin" -999.00 "tlag" 0.100000 "ddn" 20.000000
"dup" 0.000000 "frgflg" 0.0 "outflag" 0.0
lhvrt 60430 '[redacted] " 0.80 "1 " : #9 "vref" 1.00 "dvtrp1" 0.20 "dvtrp2" 0.18 "dvtrp3" 0.15
"dvtrp4" 0.10 "dvtrp5" 0.05 "dvtrp6" -1.00 "dvtrp7" -0.55 "dvtrp8" -0.10 "dvtrp9" -0.05 "dvtrp10" 0.00
"dttrp1" 0.00 "dttrp2" 1.00 "dttrp3" 2.00 "dttrp4" 3.00 "dttrp5" 99.00 "dttrp6" 1.00 "dttrp7" 1.75
"dttrp8" 4.00 "dttrp9" 999.00 "dttrp10" 0.008334 "alarm" 0.0
lhfrt 60430 '[redacted] " 0.80 "1 " : #9 "fref " 60.00 "dftrp1" 1.70 "dftrp2" 1.60 "dftrp3" 0.60
"dftrp4" -3.00 "dftrp5" -2.20 "dftrp6" -1.60 "dftrp7" -0.60 "dftrp8" 0.00 "dftrp9" 0.00 "dftrp10" 0.00
"dttrp1" 30.00 "dttrp2" 180.00 "dttrp3" 999.0 "dttrp4" 7.50 "dttrp5" 30.00 "dttrp6" 180.00
"dttrp7" 999.00 "dttrp8" 0.008334 "dttrp9" 0.008334 "dttrp10" 0.008334 "alarm" 0.0
```

In Figure 2 below is the transient stability plot of a 3-phase fault on the [redacted] 138kV bus with 9 cycles clearing and loss of the [redacted] 138kV line, an adjacent line to the [redacted] 138kV line. My first observation is that the plant controller response is way too aggressive and will probably require it to be detuned/slowed down even though the reactive response doesn't appear to be under-damped. And, the data provided for the low and high voltage and frequency trip setting of the inverter has not been verified to determine if they are compliant with NERC PRC-024 regional differences.

Additional more comprehensive transient stability analysis will be conducted in the System Impact Study should the interconnection customer choose to proceed to that study phase of the interconnection process

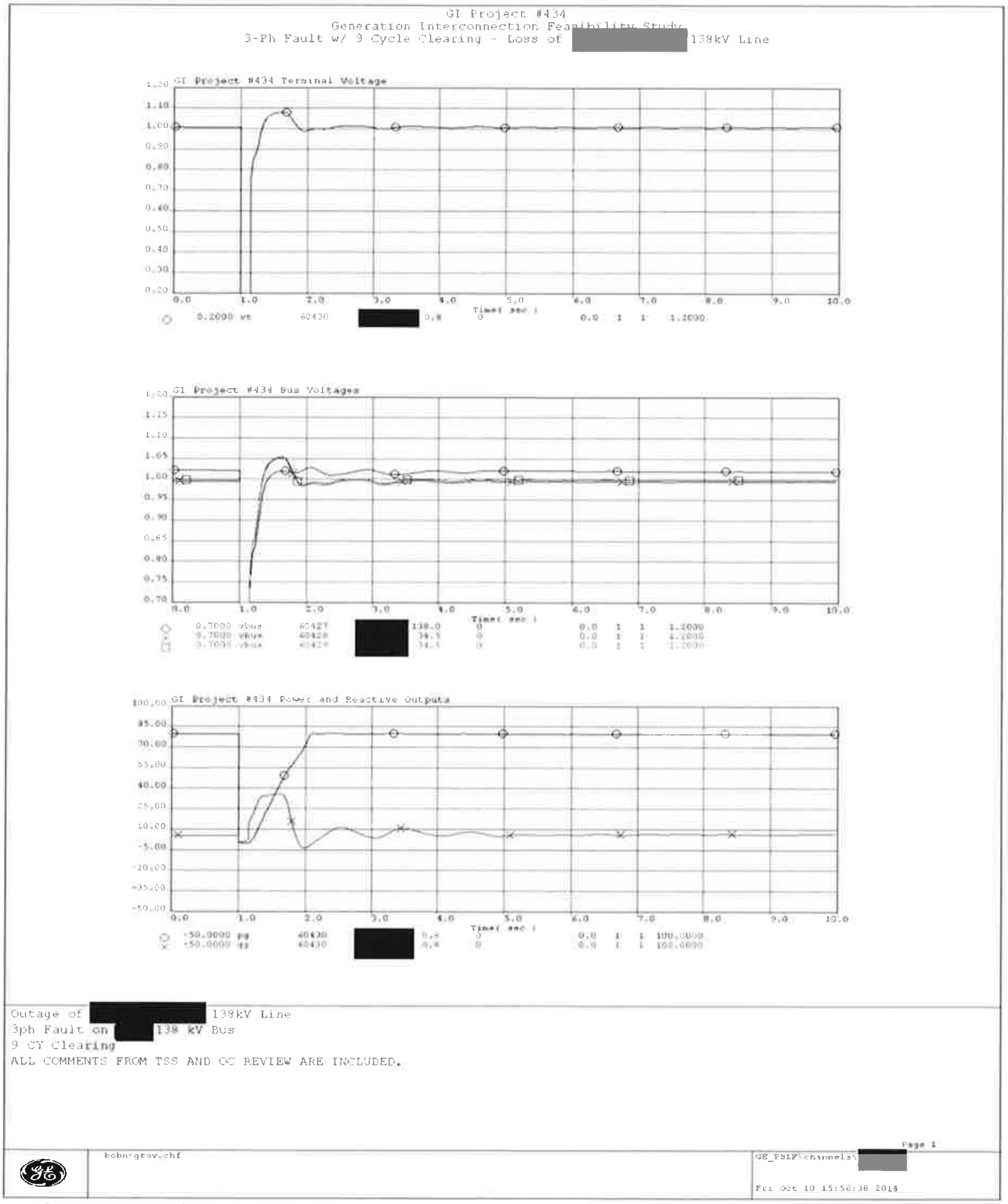

Figure 2 Transient Stability Plot

12.0 Description of Operating Requirements

The installed reactive power capability of the project must have a power factor operating range of 0.95 leading to 0.95 lagging at the point of interconnection (POI) over the range of real power output (up to maximum output of 80 MW) with Idaho Power's 138kV transmission voltage within its nominal operating voltage range of 1.00 – 1.05pu for this location due to its proximity to a strong source. So, when the Project is supplying reactive to the 138kV system (soft voltages) it is expected the 0.95 lagging power factor to be at least available at the lower limit of the acceptable voltage range (i.e. 1.00pu). Corollary, when the Project is absorbing reactive from the 138kV system (high voltages), it is expected the 0.95 leading power factor to be at least available at the higher limit of the acceptable voltage range (i.e. 1.05pu). Any additional reactive compensation to meet these requirements was modeled at the 34.5kV bus (low-side of the 138/34.5kV transformer).

Preliminary power flow analysis indicates that the reactive compensation range of the proposed GI Project #434 does not have sufficient capacity to provide a 0.95 lagging power factor at the POI at full output. The lagging plant reactive compensation capacity is 0.967 at the POI at full load, and falls shy of the 0.95 lagging requirement due to reactive losses in the transformers and collector system. Adding a 5.2 MVAR switched shunt capacitor at the 34.5kV bus will fulfill this requirement. The leading plant reactive compensation capacity however, is sufficient to meet the operating requirement of 0.95 leading at the POI at full load.

Identification of any additional equipment required at the plant to meet Idaho Power reactive power capability interconnection requirements will be provided in the System Impact study should the interconnection customer chose to proceed to that study phase of the interconnection process.

GI Project #434 will be required per NERC requirements to control voltage in accordance with a voltage schedule as provided by Idaho Power Grid Operations. GI Project #434 is required to install a plant controller for managing the real and reactive power output of the 80MW inverter array at the project POI.

Voltage flicker at startup and during operation will be limited to less than 5% as measured at the POI. The project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-1992 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.*

Installation of a phasor measurement unit device (PMU) at the POI and maintenance costs associated with communication circuits needed to stream pmu data will also be required to be provided to Idaho Power in order to interconnect GI Project #434. The cost estimates included in this Feasibility Study include costs associated with providing a PMU function from the [redacted] relay included as part of the required line protection system equipment. Additional details regarding specific PMU channel and data rate requirements will be identified in the Facility

Study should the interconnection customer choose to proceed to that phase of the interconnection process.

13.0 Cost Estimates of Required Facilities

Explanation of Costs

The cost estimate includes both Direct Assign 'DA' costs and Network Upgrades 'NU' (definitions of cost allocations provided below). The Interconnection Customer is responsible for all of the Direct Assign costs; the Transmission Provider is responsible for the Network Upgrades however they will be secured by the Interconnect Customer. If the Network Upgrades are associated with a PURPA project, then they become the sole responsibility of the Interconnection Customer. Interconnect Customers Interconnection Facilities 'ICIF' are the sole responsibility of the Interconnection Customer.

Idaho Power Company Open Access Transmission Tariff Definitions for Cost allocations:

Direct Assignment Facilities ('DA'): Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

Interconnection Customer's Interconnection Facilities ('ICIF'): Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

Network Upgrades ('NU'): Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

Estimated Costs

In Table 1 below is a summary of the generation interconnection costs to interconnect the [redacted] generation project to Idaho Power's [redacted] 138kV transmission line.

[redacted] Project POI – Tap on the [redacted] 138kV Line	
Direct Assigned Facilities for Generation Interconnection (project responsibility & non-refundable):	**Cost**
[redacted] Generation Interconnection Station	$825,000
Digital Communication From [redacted] to [redacted] Generation Interconnection Station	$510,000

138kV Transmission Line Upgrades at Tap Location	$180,000
Subtotal	**$1,515,000**
Contingencies	$303,000
Overheads	$363,600
Total Estimated Cost	**$2,181,600**

Table 1: Estimated Total Costs for Generation Interconnection of the Project

Cost estimates are given in 2014. The cost estimate includes direct equipment and installation labor costs, indirect labor costs and general overheads, and a contingency allowance. They will need to be revisited if the project is built at a much later date. These are cost estimates only and final charges to the customer will be based on the actual construction costs incurred. Allowance for funds used during construction (AFUDC) has not been included in the cost estimates since it is assumed that IPC will be provided up-front funding by the Interconnect Customer. Note that this estimate does not include the cost of the customer's equipment.

14.0 Conclusion

The requested interconnection of the [redacted] Project (GI Project #434) to Idaho Power's system was studied. The project will tap the [redacted] 138kV line between [redacted] and [redacted] in IPCo's Capital Region in Ada County, Idaho.

The results of this study work confirm that it is feasible to interconnect the GI Project #434 Project to the existing Idaho Power system. With the Interconnection Customer adding a 5.2 MVAR 34.5kV switched shunt capacitor, GI Project #434 will be able to meet the IPCo power factor requirements. Transmission system upgrades may be required to integrate the 80 MW project as a network resource. A System Impact Study is required to determine the specific network upgrades required to integrate the project and to evaluate the system impacts (thermal overload, voltage, transient stability, reactive margin).

All generation projects in the area ahead of this project in the IPCo generation interconnection queue and their associated transmission system improvements were modeled in a preliminary power flow analysis to evaluate the feasibility of interconnecting GI Project #434. The results and conclusions of this feasibility study are based on the realization of these projects in the unique queue/project order.

The estimated cost to interconnect GI Project #434 to the IPCo System at the 138kV point of interconnection considered in this study is approximately $2,181,600.

Generator interconnection service (either as an Energy Resource or a Network Resource) does not in any way convey any right to deliver electricity to any specific customer or point of delivery. Transmission service requirements to integrate this project will be determined during the System Impact Study phase of the generator interconnection process.

APPENDIX A

A-1.0 Method of Study

The Feasibility Study plan inserts the Project up to the maximum requested injection into the selected Western Electric Coordinating Council (WECC) power flow case and then, using Power World Simulator or GE's Positive Sequence Load Flow (PSLF) analysis tool, the impacts of the new resource on Idaho Power's transmission system (lines, transformers, etc.) within the study area are analyzed. The WECC and Idaho Power reliability criteria and Idaho Power operating procedures were used to determine the acceptability of the configurations considered. For distribution feeder analysis, Idaho Power utilizes Advantica's SynerGEE Software.

A-2.0 Acceptability Criteria

The following acceptability criteria were used in the power flow analysis to determine under which system configuration modifications may be required:

The continuous rating of equipment is assumed to be the normal thermal rating of the equipment. This rating will be as determined by the manufacturer of the equipment or as determined by Idaho Power. Less than or equal to 100% of continuous rating is acceptable.

Idaho Power's Voltage Operating Guidelines were used to determine voltage requirements on the system. This states, in part, that distribution voltages, under normal operating conditions, are to be maintained within plus or minus 5% (0.05 per unit) of nominal everywhere on the feeder. Therefore, voltages greater than or equal to 0.95 pu voltage and less than or equal to 1.05 pu voltage are acceptable.

Voltage flicker during starting or stopping the generator is limited to 5% as measured at the point of interconnection, per Idaho Power's T&D Advisory Information Manual.

Idaho Power's Reliability Criteria for System Planning was used to determine proper transmission system operation.

All customer generation must meet IEEE 519 and ANSI C84.1 Standards.

All other applicable national and Idaho Power standards and prudent utility practices were used to determine the acceptability of the configurations considered.

The stable operation of the system requires an adequate supply of volt-amperes reactive (VARs) to maintain a stable voltage profile under both steady-state and dynamic system conditions. An inadequate supply of VARs will result in voltage decay or even collapse under the worst conditions.

Equipment/line/path ratings used will be those that are in use at the time of the study or that are represented by IPCo upgrade projects that are either currently under construction or whose budgets have been approved for construction in the near future. All other potential future ratings are outside the scope of this study. Future transmission changes may, however, affect current facility ratings used in the study.

A-3.0 Electrical System Protection Guidance

IPCo requires electrical system protection per Requirements for Generation Interconnections found on the Idaho Power Web site,

http://www.idahopower.com/pdfs/BusinessToBusiness/facilityRequirements.pdf