System Impact Study Report
Request # GI-2007-2 Scenario A[1]

675 MW Integrated Gasification Combined Cycle (IGCC) Facility
Near Las Animas, Colorado

PSCo Transmission Planning
September 21, 2007

Executive Summary

PSCo Transmission received a generation request to determine the feasibility of interconnecting a 675 MW IGCC Plant at a new 500 kV Southeast (SE) Tap 500kV Switching Station. The Customer proposed commercial operation date is May 2014 with an assumed back feed date of September 2012. This request was studied as a Network Resource (NR)[2] connecting to the Tri-State Generation and Transmission Association's (TSGT) and Western Area Power Administration's (WAPA) Eastern Plains Transmission Project (EPTP). **To meet the Customer proposed In-Service Dates (back feed and commercial), the Large Generator Interconnection Agreement (LGIA) or an Engineer and Procure (E&P) Agreement must be fully executed by January 2008.**

This System Impact Study did not determine the cost of utilizing the EPTP for delivery of the 675 MW of generation to PSCo native load. The cost of transmission service from Tri-State and Western or the cost to become a joint participant in the EPTP was not determined.

The Affected Utilities for this study are Aquila, Arkansas River Power Authority (ARPA) and its members, Colorado Springs Utilities (CSU), Tri-State Generation and Transmission (TSGT) and its members, and Western Area Power Adminstration (WAPA). Efforts were made to minimize impacts to these utilities. Pre-existing issues on the Affected Utilities will be addressed with either operating procedures or through joint long-range studies before the EPTP goes into service.

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[1] This study is Scenario A includes the Eastern Plains Transmission Projects (EPTP) where Scenario B is the stand alone without the EPTP will conducted providing the Customer wishes this scenario.

[2] Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as all other Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Results

Network Resource:

PSCo evaluated the network to determine the upgrades required to deliver the full 675 MW of the IGCC to PSCo native load customers via the EPTP. The initial phase of EPTP is shown in Figure 1.

The total estimated cost of the recommended system upgrades to accommodate the project is approximately **$104.92** million and includes:

- $74.45 million for Transmission Provider Owned, Customer Funded Interconnection Facilities
- $10.16 million for Transmission Provider Network Upgrades for Interconnection
- $20.31 million for Transmission Provider Network Upgrades for Delivery

These basic upgrades including interconnection as shown in Figure 2 would consist of:

1. Constructing a new 500 kV Station at Las Animas just outside the proposed IGCC for both Interconnection and Delivery
2. Construct two new 31-mile 500 kV lines from the Las Animas IGCC Switching Station to the SE TAP Switching Station
3. Construct a new 500 kV SE TAP switching Station that interconnects to the 500 kV EPTP line between Lamar Energy Center and Boone for Interconnection and Delivery
4. Add a new 345/500 kV autotransformer at Midway to connect Western's 500 kV yard to PSCo's 345 kV yard.
5. Construct a new 345 kV yard at Green Valley including 345/230 kV autotransformation.

Estimates have been provided for items 1 through 5.

A partial one-line of the Las Animas Switching Station detailing the Interconnection and Delivery is shown in Figure 2.

The estimated time required to engineer, permit, and construct all the required PSCo facilities for interconnection is estimated to be at 57 months as shown in Table 1. Therefore, the requested back feed date of September 2012 is achievable providing the project is started in January 2008. The estimated time required to engineer, permit, and construct the Network Upgrade facilities for delivery is 77 months as shown in Table 2 once the project has started and EPTP is constructed as planned by 2014.

The Customer should be aware that voltages on the interconnecting bus and at their facility made be in excess of 1.05 pu during light loads or periods when the IGCC is not operating. Reactive compensation for charging current of the EPTP has not yet been designed for these light load periods. This will be addressed in the Facilities Study should the Customer decide to continue this request.

Figure 1: Initial phase of EPTP before Las Animas IGCC Interconnection (Study Base Case)

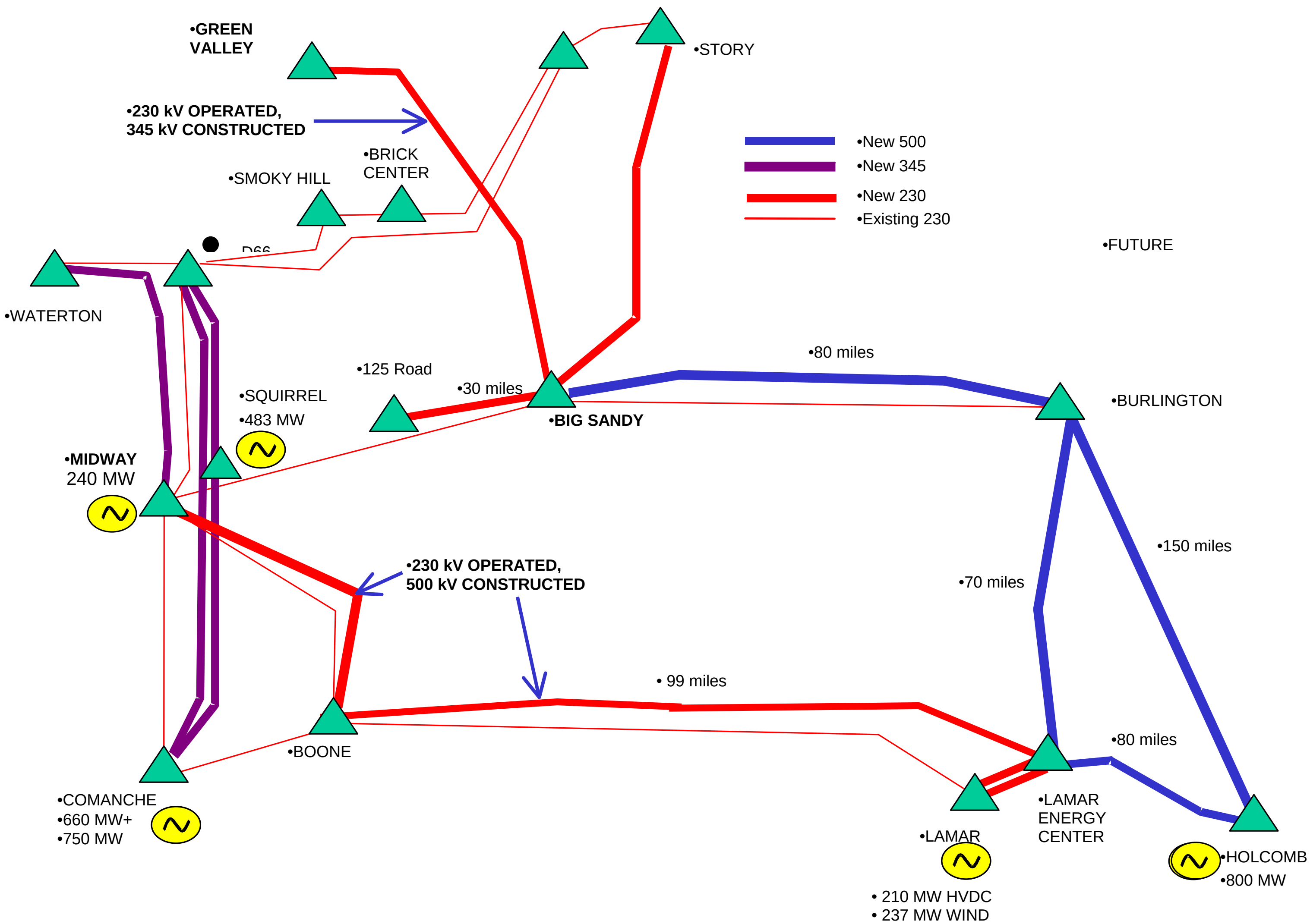
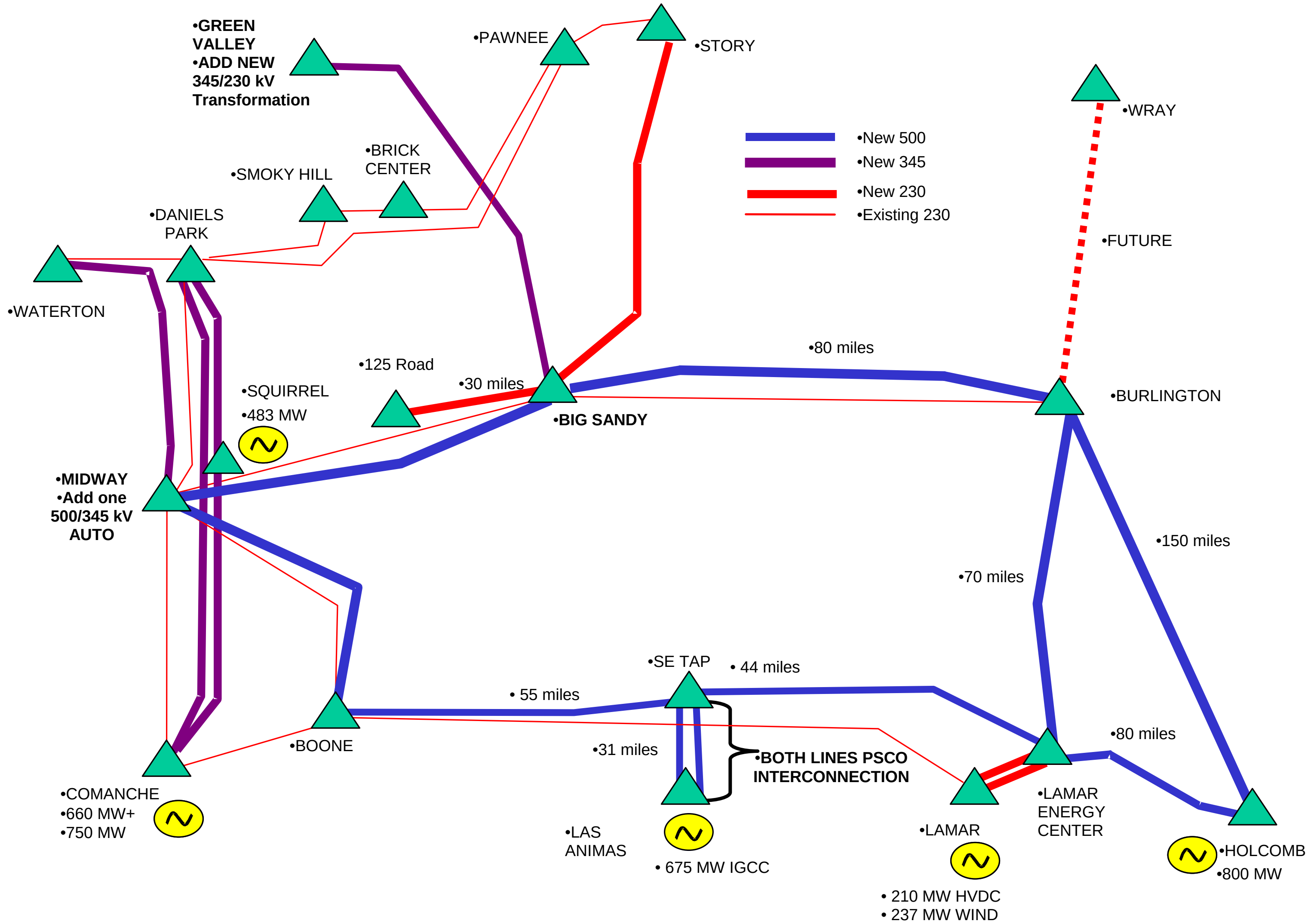


Figure 2 – EPTP Transmission Network Including Recommended Upgrades for the IGCC Delivery (Scenario 9b)



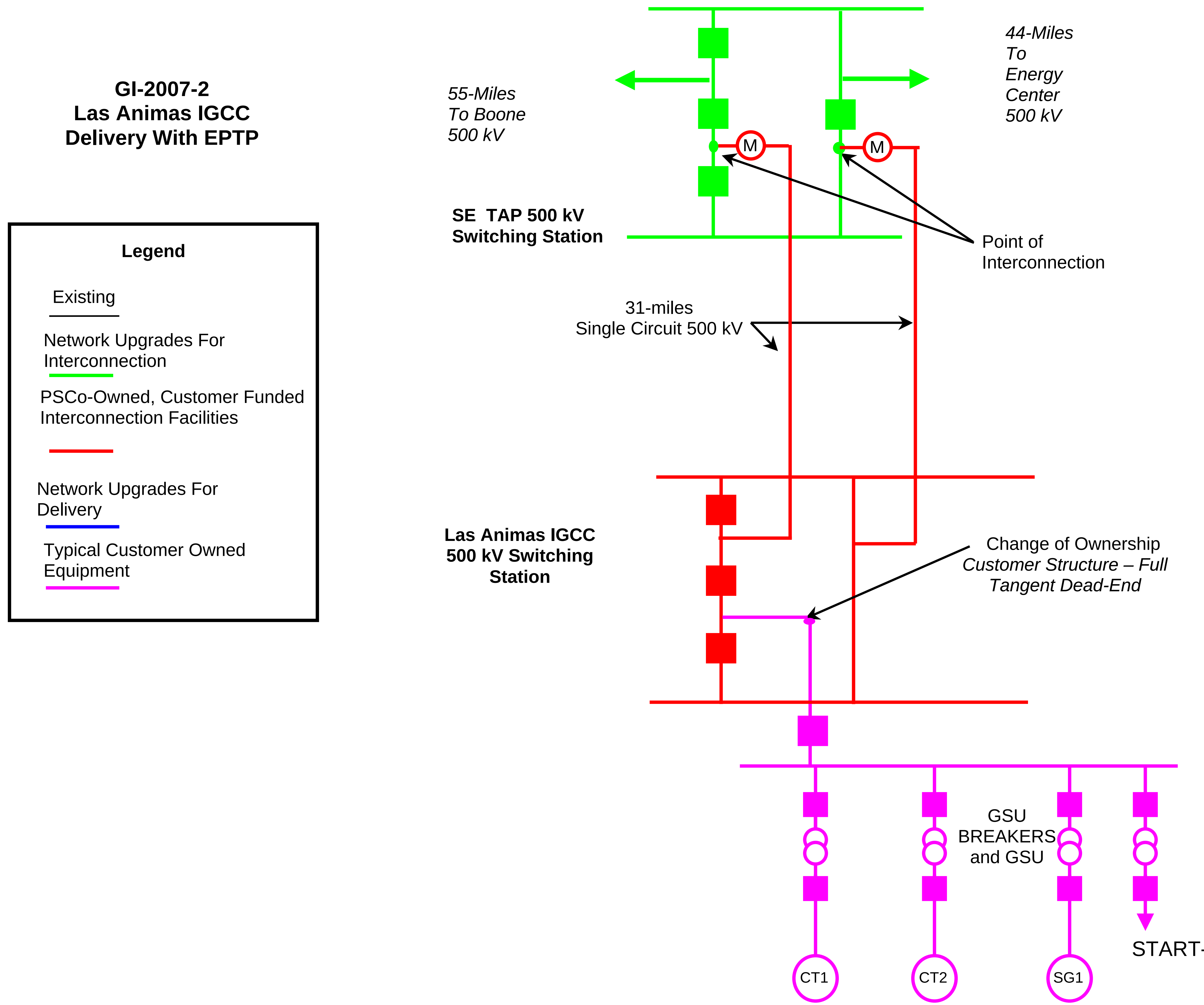


Figure 2: Las Animas IGCC Interconnection One-line

Study Scope and Analysis

The Interconnection System Impact Study evaluated the transmission requirements associated with the proposed interconnection to the PSCo Transmission System. It consisted of power flow, short circuit, and dynamic stability analyses. The power flow analysis provided a preliminary identification of any thermal or voltage limit violations resulting for the interconnection, and for a NR request, a preliminary identification of network upgrades required to deliver the proposed generation to PSCo loads. The short circuit analysis identified any circuit breaker short circuit capability limits exceeded as a result of the Interconnection and for a NR request, the delivery of the proposed generation to PSCo loads. The dynamic stability analysis identified any limitations due to angular instability of the system for regional disturbances

PSCo adheres to NERC / WECC Reliability Criteria, as well as internal Company criteria for planning studies. During system intact conditions, transmission system bus voltages are to be maintained between 0.95 and 1.05 per-unit of system nominal / normal conditions, and steady state power flows within 1.0 per-unit of all elements' thermal (continuous current or MVA) ratings. Operationally, PSCo tries to maintain a transmission system voltage profile ranging from 1.03 per-unit or higher at generation buses, to 1.0 per-unit or higher at transmission load buses. Following a single contingency element outage, transmission system steady state bus voltages must remain within 0.90 per-unit to 1.10 per-unit, and power flows within 1.0 per-unit of the elements continuous thermal ratings.

Study Models

The power flow studies were based on a 2014 power flow case that was developed from the approved Western Electricity Coordinating Council (WECC) 2015 heavy summer base model. The loads were adjusted in the Rocky Mountain Region for the 2014 summer time frame. The Customer's 675 MW IGCC was modeled with Customer provided details and a +/-0.95 per unit (p.u.) power factor capability at the Point of Interconnection (POI) to simulate required VAR output. The project generation was dispatched to replace northern PSCo generation.

The (POI) between the Customer and PSCo is assumed to be the point at which the Customer connects to the proposed SE Tap Switching Station 500 kV bus. For this 500 kV interconnection, typical GSU transformer impedances were used for the Customer's equipment.

Efforts were made to include in the models all transmission projects expected to be in service for the 2014 heavy summer season. The studies assumed 2014 peak summer demand conditions in the PSCo system and in other utility systems. Generation in Southern Colorado was dispatched accordingly such as the Lamar HVDC Tie was at

210 MW, and the full 237 MW output of Colorado Green and Twin Buttes wind farms was included in the generation mix. Appendix B states system configuration and generation dispatch assumptions.

Power Flow Study Results and Conclusions

Network Resource (NR) Study Results

The NR study determined the network upgrades that would be required to accept the full 675 MW from the proposed generating plant for the conditions studied. The starting base case had a number of pre-existing contingency overloads. At 675 MW of generation from the Customer, these issues were compounded and a number of additional contingency overloads arose. The recommended solution (Scenario 9b) mitigated these overloads and minimized the impacts on the Affected Utilities. The table in Appendix A shows the most significant contingencies and the associated overloads along with results from the benchmark case, benchmark case with IGCC, and with the recommended Network Upgrades for Delivery.

No attempt was made to fix the pre-existing contingency overloads. These will have to be addressed in joint long-range planning studies and/or through the Affected Utilities' operating procedures.

Short Circuit Study Results

The short circuit study results show that the fault current levels for most buses studied are within the interrupting ratings of the breakers; however, the Project and associated infrastructure will cause fault current to exceed the 32,000 amp circuit breaker rating of two circuit breakers at Smoky Hills and one circuit breaker at Daniels Park.

The fault currents at the Tap Substation are 24,204 Amps for a single-line to ground fault and 23,912 Amps for a three-phase fault.

Dynamic Stability Results

Transient stability analyses were performed by modeling three-phase faults in the region of study. Dynamic models for the proposed project were prepared using Customer supplied data. The analysis indicated the system is stable before, during, and after contingencies once network upgrades were implemented.

The tables in Appendix B show stability results before and after the project and Network Upgrades are added to the system.

Costs Estimates and Assumptions

The estimated total cost for the required upgrades is **$104,920,000.**

The estimated costs shown are "scoping" (+/-30%) estimates in 2007 dollars and are based upon typical construction costs for similar construction. These estimated costs include all applicable labor and overheads associated with the engineering, design, and construction of these new PSCo facilities. This estimate does not include any costs for any Customer-owned, supplied, and installed equipment and associated design and engineering. This estimate also does not include any costs that may be required for other entities' systems and do not include costs to obtain Transmission Service from TSGT. The following tables list the improvements required to accommodate the interconnection and the delivery of the Project. The cost responsibilities associated with these facilities shall be handled as per current FERC guidelines. System improvements are subject to change upon more detailed analysis.

The estimated costs for interconnection are detailed in Table 1 and Table 2. Table 3 shows the detailed costs for Network Upgrades required for Firm Delivery.

Table 1 – Transmission Provider Owned Customer Funded Interconnection Facilities

Element	Description	Cost Est. Millions
SE TAP Switching Station	PSCo's new 500 kV Las Animas Substation Metering and Communications and Witness Testing.	**$0.92**
Transmission	Transmission tie line into Las Animas IGCC Substation.	**$0.25**
	Two 31-mile Las Animas - SE TAP Single Circuit 500 kV Lines using a 3/C 1272 ACSR Bittern conductor per phase.	**$62.88**
Siting and Land Rights	Siting and Land Rights for required easements, reports, permits and licenses.	**$2.30**
Las Animas 500kV Switching Station	500kV line terminal to SE Tap Station. The following equipment will be required: Three 500 kV, 2000 amp, 40kA circuit breakers Ten 500 kV, 2000 amp switches Misc. supporting steel and foundations Electric bus work Associated control, relaying and testing	**$8.10**
TOTAL		**$74.45**

Table 2 – Transmission Provider Network Upgrades for Interconnection

Element	Description	Cost Est. Millions
SE TAP Switching Station	500 kV line into new 500 kV Yard. The new equipment required includes: Three new 500 kV, 2000 amp circuit breakers Ten 500 kV, 2000 amp switches Transmission line relaying and testing Required steel supporting structures and foundations	**$8.37**
SE TAP Switching Station	New 500 kV Line terminals to Las Animas Switching Station requiring the following equipment: One 500kV, 2000 amp circuit breaker Two 500kV , 2000 amp switches Required steel and foundations Electric bus work Control, relaying and testing	**$1.73**
Siting and Land Rights	Obtain necessary siting, permits, and ROW as required	**$0.06**
TOTAL		**$10.16**
Time Frame for Table 1 and Table 2		**57 Months**

Table 3 – PSCo Network Upgrades for Delivery

Element	Description	Cost Est. Millions
Midway Substation	A new 500/345 kV autotransformer to interconnect the PSCo 345 kV yard with Western's 500 kV yard. This includes the following equipment: Two 345 kV 2000 Amp 40 kA circuit breakers One 345/500 kV 560 MVA autotransformer One 345 kV 3000 Amp, gang switch Associated steel and foundations Associated control, relaying, and testing Electrical bus work	**$7.06**
Green Valley Substation	Two new 345/230 kV autotransformers to interconnect the PSCo 345 kV yard with the 230 kV yard. This includes the following equipment: Three 345 kV 2000 Amp 40 kA circuit breakers Two 345/230 kV 560 MVA autotransformer Eight 345 kV 2000 Amp, gang switches Four 230 kV 3000 Amp circuit breakers Eight 230 kV 3000 Amp, gang switches Associated steel and foundations Associated control, relaying, and testing Electrical bus work	**$13.25**
	Total Cost Estimate for PSCo Network Upgrades for Delivery	**$20.31**
	Total Cost of Project	**$104.92**
Time Frame		**77 Months**

Assumptions

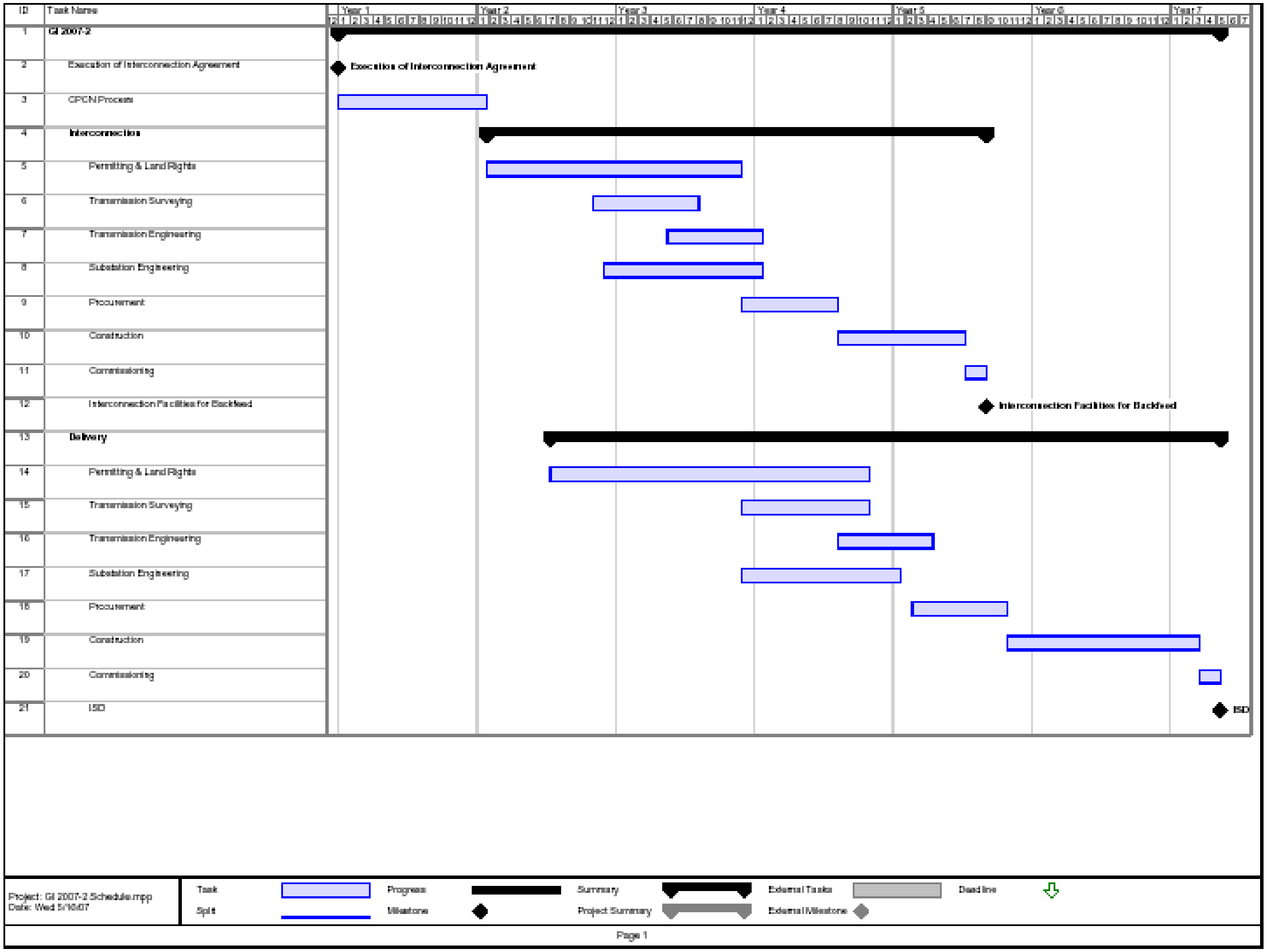
- The estimates and time frames given are for reference only are subject to change with a more detailed system study.
- The cost estimates provided are "scoping estimates" with an accuracy of +/- 30%.
- Estimates are based on **2007** dollars.
- PSCo crews will perform all substation construction and wiring associated with PSCo owned and maintained facilities. Contractor Crews may perform transmission line construction. It is assumed that all work will be done on straight time.
- The estimated time for design and construction of PSCo network upgrades for interconnection at the SE Tap Switching Station is 57 months.
- It is anticipated that in order to construct the PSCo network upgrades for Delivery and Interconnection, a Certificate of Public Convenience and Necessity (CPCN) will be required by the Colorado Public Utilities Commission (CPUC). The application for a CPCN will not be submitted until the Interconnection Agreement is fully executed. The estimated time frame for the CPCN process for the PSCo network upgrades is at least 14 months from the time the Interconnection Agreement is fully executed.
- A siting study will be required for network upgrades for interconnection and delivery. Extensive public involvement is anticipated. Permit applications and possible minor right-of-way acquisition will be required. Land use permits will be required from multiple local jurisdictions.
- This interconnection and delivery easement acquisition affects the following entities: Bent, Kiowa Counties.
- Five temporary staging areas for line construction at 5 acres per site will be needed and are included in this estimate.
- Any 500 kV single circuit line will require 200' width easements along the planned route. Two 500kV Single Circuits side by side on separate poles will require 400' easements.
- Implementation of the recommended infrastructure for Delivery and Interconnection will require that existing facilities be taken out of service for sustained periods. In most cases, these outages cannot be taken during peak load periods due to operational constraints. As a result, the estimated time frame for implementation could be increased.
- The last spans into SE Tap Switching Station from the Customer funded 500 kV line will be a slack span between the Transmission Provider's substation dead-end and the Customer's last structure, which is assumed to be a dead-end tangent structure.

Project Schedule

The following schedule, depicted in Figure 3, identifies the main milestones needed to complete the interconnection and the delivery portion of the proposed 675 MW IGCC generation facility.

The following schedule identifies project milestones for three separate phases of work needed to complete the proposed interconnection: Siting, Permitting & Land Acquisition, Substation Design & Construction and Transmission Line Design & Construction. The total estimated duration to complete all of the required activities and tasks is 77 months.

Figure 3 – Preliminary Schedule



Appendix A
Contingency Comparison Table
Report Table #4

Overloaded Element									Case	Base (Figure 1) + Full Lamar Wind + HVDC Import 210 MW + Ft. Valley Fullout			IGCC + Full Lamar Wind + HVDC Import 210 MW + Ft. Valley Fullout				Recommended Solution (Figure 2): Midway-B.Sandy @ 500 kV + B.Sandy-G. Valley @ 345 kV+Midway 500/345 kV Auto #3				
From Bus #	From ---name---	kV	Area	To Bus #	To ---name---	kV	Area	ID	Rating [MVA]	Pre-Cnt Load	Cnt Load	Cnt #	Base Load	Cnt Load	Cnt #	∆ Cnt Load Scn7 - Bs	Pre-Cnt Load	Cnt Load	Cnt #	∆ Cnt Load Scn7 - Bs	List Of Contingencies
70002	"BURNT MI"	115	70	70004	"FREEMARY"	115	70	1	99	65%	116%	393	0.72	126%	393	10%	62%	110%	393	-6%	70339 PUEBLO 115 TO 70352 READER 115
70002	"BURNT MI"	115	70	70456	"W.STATON"	115	70	1	99	65%	115%	393	0.72	126%	393	11%	62%	109%	393	-6%	70339 PUEBLO 115 TO 70352 READER 115
70004	"FREEMARY"	115	70	70352	"READER "	115	70	1	99	78%	128%	393	0.84	139%	393	11%	75%	122%	393	-6%	70339 PUEBLO 115 TO 70352 READER 115
70042	"ASPEN TP"	69	70	70051	"BLENDE "	69	70	1	57	83%	103%	170	0.85	106%	393	3%	82%	102%	69	-1%	70054 BMONT TP 069 TO 70305 OVERTON 069
70042	"ASPEN TP"	69	70	70353	"READER "	69	70	1	57	83%	103%	170	0.85	106%	393	3%	82%	102%	69	-1%	70054 BMONT TP 069 TO 70305 OVERTON 069
70049	"BELMONT "	69	70	70305	"OVERTON "	69	70	1	48	24%	104%	45	0.30	104%	45	0%	25%	102%	45	-2%	70042 ASPEN TP 069 TO 70051 BLENDE 069
70054	"BMONT TP"	69	70	70305	"OVERTON "	69	70	1	48	35%	126%	45	0.41	126%	45	0%	37%	125%	45	-1%	70042 ASPEN TP 069 TO 70051 BLENDE 069
70054	"BMONT TP"	69	70	70455	"W.STATON"	69	70	1	59	29%	103%	45	0.33	103%	45	0%	30%	102%	45	-1%	70042 ASPEN TP 069 TO 70051 BLENDE 069
70121	"COMANCHE"	115	70	70352	"READER "	115	70	2	160	85%	170%	166	0.82	164%	166	-6%	82%	163%	166	-7%	70121 COMANCHE 115 TO 70352 READER 115
70121	"COMANCHE"	115	70	70352	"READER "	115	70	1	160	85%	170%	167	0.82	164%	167	-6%	82%	163%	167	-7%	70121 COMANCHE 115 TO 70352 READER 115
70121	"COMANCHE"	115	70	70122	"COMANCHE"	230	70	A1	176	81%	130%	1284	0.78	124%	1287	-6%	78%	125%	1292	-5%	70122 COMANCHE 230 TO 70654 COMANCHE 34
70121	"COMANCHE"	115	70	70122	"COMANCHE"	230	70	A2	184	78%	124%	1283	0.75	119%	1286	-5%	76%	120%	1291	-4%	70122 COMANCHE 230 TO 70654 COMANCHE 34
70122	"COMANCHE"	230	70	70459	"WALSENBG"	230	70	1	239	96%	134%	391	1.01	140%	391	6%	97%	136%	391	2%	70336 PUEB-TAP 115 TO 70456 W.STATON 115
70136	"CTY LAM "	69	70	70134	"CTY LAM "	24	70	2	11	51%	145%	1291	0.46	137%	1294	-8%	49%	143%	1299	-2%	70138 DANIELPK 115 TO 70139 DANIELPK 230
70136	"CTY LAM "	69	70	70134	"CTY LAM "	24	70	1	25	67%	105%	1288	0.60	105%	1291	0%	65%	105%	1296	0%	70134 CTY LAM 024 TO 70226 HOLLY 025
70138	"DANIELPK"	115	70	70139	"DANIELPK"	230	70	T1	150	85%	107%	482	0.85	105%	467	-2%	86%	107%	467	0%	70463 WATERTON 115 TO 70522 ROXBOROU 11
70139	"DANIELPK"	230	70	70331	"PRAIRIE "	230	70	1	495	75%	111%	184	0.96	143%	184	32%	88%	130%	184	19%	70139 DANIELPK 230 TO 70323 PRAIRIE2 230
70139	"DANIELPK"	230	70	70323	"PRAIRIE2"	230	70	1	495	63%	105%	185	0.83	138%	185	33%	75%	124%	185	19%	70139 DANIELPK 230 TO 70331 PRAIRIE 230
70139	"DANIELPK"	230	70	70601	"DANIELPK"	345	70	2	560				0.69	101%	1297	101%				0%	70139 DANIELPK 230 TO 70601 DANIELPK 345
70139	"DANIELPK"	230	70	70601	"DANIELPK"	345	70	3	560				0.69	101%	1297	101%				0%	70139 DANIELPK 230 TO 70601 DANIELPK 345
70139	"DANIELPK"	230	70	70601	"DANIELPK"	345	70	1	560				0.69	101%	1298	101%				0%	70148 DENVTM 115 TO 70149 DENVTM 230
70212	"GREENWD "	230	70	70323	"PRAIRIE2"	230	70	1	495	63%	105%	185	0.83	138%	185	33%	75%	124%	185	19%	70139 DANIELPK 230 TO 70331 PRAIRIE 230
70212	"GREENWD "	230	70	70331	"PRAIRIE "	230	70	1	495				0.68	115%	184	115%	60%	102%	184	102%	70139 DANIELPK 230 TO 70323 PRAIRIE2 230
70212	"GREENWD "	230	70	70481	"MONACO12"	230	70	1	413				0.83	113%	51	113%	78%	109%	51	109%	70046 BUCKLY34 230 TO 70396 SMOKYHIL 230
70236	"HYDEPARK"	115	70	70339	"PUEBLO "	115	70	1	99	112%	189%	170	1.23	170%	3	-19%	107%	183%	170	-6%	70122 COMANCHE 230 TO 70459 WALSENBG 23
70236	"HYDEPARK"	115	70	70456	"W.STATON"	115	70	1	99	100%	176%	170	1.10	157%	3	-19%	94%	170%	170	-6%	70122 COMANCHE 230 TO 70459 WALSENBG 23
70254	"LAMAR CO"	230	70	70253	"LAMAR CO"	115	70	1	100	113%	136%	1036	1.17	170%	1253	34%	100%	121%	1254	-15%	73584 BOONE 500 TO 73581 BL_TAP 500
70259	"LEETSDAL"	115	70	70443	"UNIVRSTP"	115	70	1	109				0.72	145%	30	145%	70%	143%	30	143%	70036 ARAPAHOA 115 TO 70037 ARAPAHOB 115
70260	"LEETSDAL"	230	70	70481	"MONACO12"	230	70	1	413				0.76	106%	51	106%	71%	102%	51	102%	70046 BUCKLY34 230 TO 70396 SMOKYHIL 230
70294	"NCANON W"	69	70	70451	"VICTOR "	69	70	1	24	12%	114%	1271	0.14	119%	1274	5%	12%	114%	1279	0%	70097 CF&ISE1- 069 TO 70096 CF&ISE1 115
70308	"PALMER "	115	70	73414	"MONUMENT"	115	73	1	134.8	77%	102%	1203	1.03	142%	1203	40%	82%	113%	1203	11%	73477 FULLER 230 TO 70139 DANIELPK 230
70329	"PORTLAND"	69	70	70330	"PORTLAND"	115	70	2	25	36%	100%	1329	0.36	101%	1332	1%	36%	100%	1339	0%	70334 PUB DSLS 004 TO 70338 PUEBLO 069
70330	"PORTLAND"	115	70	70456	"W.STATON"	115	70	1	80	70%	118%	988	0.82	143%	989	25%	71%	131%	989	13%	73551 W CANON 230 TO 73413 MIDWAYBR 230
70336	"PUEB-TAP"	115	70	70456	"W.STATON"	115	70	1	95	95%	320%	170	0.99	108%	1374	-212%	99%	325%	170	5%	70122 COMANCHE 230 TO 70459 WALSENBG 23
70339	"PUEBLO "	115	70	70352	"READER "	115	70	1	159	74%	122%	170	0.81	110%	3	-12%	71%	118%	170	-4%	70122 COMANCHE 230 TO 70459 WALSENBG 23
70353	"READER "	69	70	70352	"READER "	115	70	2	47	70%	119%	1337	0.70	119%	1340	0%	69%	118%	1347	-1%	70354 RIDGE 115 TO 70355 RIDGE 230
70353	"READER "	69	70	70352	"READER "	115	70	1	47	70%	119%	1338	0.70	119%	1341	0%	69%	118%	1348	-1%	70354 RIDGE 115 TO 70355 RIDGE 230
70456	"W.STATON"	115	70	70455	"W.STATON"	69	70	1	42	63%	123%	45	0.64	123%	45	0%	64%	123%	45	0%	70042 ASPEN TP 069 TO 70051 BLENDE 069
70456	"W.STATON"	115	70	70455	"W.STATON"	69	70	2	42	61%	121%	45	0.63	121%	45	0%	62%	120%	45	-1%	70042 ASPEN TP 069 TO 70051 BLENDE 069
70473	"WILOW CK"	69	70	70472	"WILOW CK"	115	70	2	42	67%	121%	1379	0.68	123%	1382	2%	63%	114%	1389	-7%	70478 ZUNI1 014 TO 70148 DENVTM 115
70473	"WILOW CK"	69	70	70472	"WILOW CK"	115	70	1	42	67%	121%	1380	0.68	123%	1383	2%	63%	114%	1390	-7%	70485 ALMSACT1 014 TO 70026 ALMSA TM 069
73196	"TERRY "	115	73	73503	"ERIE SW "	115	73	1	109				0.72	109%	1014	109%	66%	100%	1014	100%	73502 DACONO 115 TO 73503 ERIE SW 115
73384	"BIRDSALE"	115	73	73422	"TEMPLTON"	115	73	1	79	69%	108%	959	0.75	119%	959	11%	73%	115%	959	7%	73397 DRAKE N 115 TO 73430 FAIRVWCS 115
73397	"DRAKE N "	115	73	73399	"DRAKE W "	35	73	1	67	71%	203%	1567	0.72	205%	1570	2%	71%	201%	1577	-2%	73407 KELKER N 230 TO 73408 KELKER E 115
73397	"DRAKE N "	115	73	73496	"ATMELSUB"	115	73	1	129				0.67	105%	962	105%	64%	101%	962	101%	73398 DRAKE S 115 TO 73409 KELKER W 115
73398	"DRAKE S "	115	73	73396	"DRAKE E "	35	73	1	67	71%	143%	1563	0.71	144%	1566	1%	71%	143%	1573	0%	73397 DRAKE N 115 TO 73429 DRAKE 7 014
73399	"DRAKE W "	35	73	73428	"DRAKE 6 "	14	73	1	85	89%	116%	1564	0.89	119%	1567	3%	89%	114%	1574	-2%	73398 DRAKE S 115 TO 73396 DRAKE E 035
73408	"KELKER E"	115	73	73496	"ATMELSUB"	115	73	1	129	84%	118%	962	0.91	129%	962	11%	88%	124%	962	6%	73398 DRAKE S 115 TO 73409 KELKER W 115

Overloaded Element									Case	Base (Figure 1) + Full Lamar Wind + HVDC Import 210 MW + Ft. Valley Fullout			IGCC + Full Lamar Wind + HVDC Import 210 MW + Ft. Valley Fullout				Recommended Solution (Figure 2): Midway-B.Sandy @ 500 kV + B.Sandy-G. Valley @ 345 kV+Midway 500/345 kV Auto #3				
From Bus #	From ---name---	kV	Area	To Bus #	To ---name---	kV	Area	ID	Rating [MVA]	Pre-Cnt Load	Cnt Load	Cnt #	Base Load	Cnt Load	Cnt #	∆ Cnt Load Scn7 - Bs	Pre-Cnt Load	Cnt Load	Cnt #	∆ Cnt Load Scn7 - Bs	List Of Contingencies
73408	"KELKER E"	115	73	73422	"TEMPLTON"	115	73	1	159				0.60	100%	980	100%					73409 KELKER W 115 TO 73420 ROCKISLD 115
73409	"KELKER W"	115	73	73420	"ROCKISLD"	115	73	1	159	85%	108%	977	0.92	118%	977	10%	89%	113%	977	5%	73408 KELKER E 115 TO 73422 TEMPLTON 115
73413	"MIDWAYBR"	230	73	73412	"MIDWAYBR"	115	73	1	100	62%	101%	1576	0.68	120%	986	19%	76%	127%	986	26%	73413 MIDWAYBR 230 TO 73419 RD_NIXON 230
73413	"MIDWAYBR"	230	73	73419	"RD_NIXON"	230	73	1	482				0.47	116%	996	116%	51%	115%	996	115%	73419 RD_NIXON 230 TO 73559 FRTRANGE 230
73584	"BOONE "	500	73	70061	"BOONE "	230	70	1	450				0.78	133%	1687	133%					73584 BOONE 500 TO 70061 BOONE 230
73584	"BOONE "	500	73	70061	"BOONE "	230	70	2	450				0.78	133%	1686	133%					73584 BOONE 500 TO 70061 BOONE 230

Color Code	
AQUILA	
CSU	
PSCO	
TSGT	
WAPA	
ARPA	
Contingency Flow Less Than 100%	

Appendix B
Stability Study Results Comparison

Table 5: Comparison of Stability Results

GI-2007-2 - IGCC Project Results of Stability Analysis			Base		With IGCC			
Fault #	Fault Location	Action	From Bus	To Bus	From Bus	To Bus	Benchmark Results Before IGCC	Results with IGCC and Network Upgrades
1	3PH at Lamar 230 kV bus, 6 cycles	Trip Boone-Lamar 230 kV line	70254	70061	70254	70061	ok	ok
2	3PH at Boone 230 kV bus, 6 cycles	Trip Boone-Lamar 230 kV line	70061	70254	70061	70254	ok	ok
3	3PH at BL TAP 500 kV Bus, 4 cycles	Trip BL TAP-Boone 500 kV Line			73581	73584	-	ok
4	3PH at BL TAP 500 kV Bus, 4 cycles	Trip BL TAP-LEC 500 kV Line			73581	73582	-	ok
5	3PH at Boone 230 kV, 6 cycles	Trip Boone-LEC 230 kV Line	70061	73586			ok	-
6	3PH at Boone 500 kV, 4 cycles	Trip Boone-BL TAP 500 kV Line			73584	73581	-	ok
7	3PH at Boone 500 kV, 4 cycles	Trip Boone-Midway 500 kV Line			73584	73583	-	ok
8	3PH at LEC 230 kV, 6 cycles	Trip LEC-Boone 230 kV Line	73586	70061			ok	-
9	3PH at LEC 500 kV, 4 cycles	Trip LEC 500/230-kV Transformer #1 or #2	73582	73586	73582	73586	ok	ok
10	3PH at LEC 500 kV, 4 cycles	Trip LEC-BL TAP 500 kV Line			73582	73581	-	ok
11	3PH at LEC 500 kV, 4 cycles	Trip LEC-Burlington 500 kV Line	73582	73590	73582	73590	ok	-
12	3PH at LEC 500 kV, 4 cycles	Trip LEC-Holcomb 500 kV Line	73582	73996	73582	73996	ok	-
13	3PH at Comanche 345 kV, 4 cycles	Trip Comanche - Daniels Park 345 kV	70654	70601	70654	70601	ok	ok
14	3PH at Comanche 345 kV, 4 cycles	Trip Comanche G3	70654	70777	70654	70777	ok	ok
15	3PH at IGCC 500 kV bus, 4 cycles	Trip BL TAP-IGCC 500 kV Line #1 or #2			70615	73581	-	ok
16	3PH at IGCC 500 kV bus, 4 cycles	Trip IGCC			70615	70641, 70642, 70643	-	high voltage
17	3PH at Boone 500 kV, 4 cycles	Trip Boone-Midway 500 kV Line & Trip Boone-BL TAP 500 kV Line			73584 73584	73583 73581	-	ok
18	3PH at LEC 500 kV, 4 cycles	Trip LEC-BL TAP 500 kV Line & Trip LEC-Burlington 500 kV Line			73582 73582	73581 73599	-	ok
19	3PH at Holcomb 500 kV, 4 cycles	Trip Holcomb-Burlington 500 kV Line			73996	73188	ok	ok

APPENDIX C

STUDY ASSUMPTIONS

<u>Base Case Study Assumptions:</u>

Generation

1. Lamar HVDC importing full 210 MW
2. Colorado Green Wind at full 162 MW output
3. Twin Buttes Wind at Full 75 MW output
4. All Comanche generation at or near maximum capacity
5. Squirrel Creek Generation at maximum capacity
6. All Fountain Valley Generation at maximum capacity
7. All Colorado Springs Utilities Generation at maximum capacity
8. TSGT Holcomb generation at 800 MW (4x 400 MW)

Transmission

9. Midway to Wateron 345 kV line is included
10. Initial Configuration of EPTP is:
    a. 230 kV line from Boone to Midway constructed to 500 kV specifications
    b. 230 kV line from Lamar Energy Center to Boone
    c. 500 kV line from Lamar Energy Center to Burlington with 50% series compensation.
    d. 500 kV line from Holcomb to Lamar Energy Center
    e. 500 kV line from Holcomb to Burlington with 50% series compensation.
    f. 500 KV line from Burlington to Big Sandy with 50% series compensation.
    g. 230 kV line from Big Sandy to Green Valley constructed to 345 kV specifications.
    h. 230 kV line from Big Sandy to Midway constructed to 500 kV specifications **not included**

Case with IGCC Study and Recommended Network Upgrades For Delivery

Generation

11. IGCC generation scheduled such that it replaces Ft. St. Vrain, Spindle, and Plains End generation.

Transmission

12. EPTP
    a. 230 kV line from Big Sandy to Green Valley constructed to 345 kV specifications now operated at 345 kV
    b. New 500/345 kV autotransformer at Big Sandy.
    c. 500 kV line from Big Sandy to Midway
    d. New 500/.345 kV autotransformer at Midway