June 27, 2006

COMMUNITY BASED ENERGY DEVELOPMENT

TRANSMISSION STUDY

WEST CENTRAL (MINNESOTA) TRANSMISSION PLANNING ZONE

JUNE 2006

I. Introduction

The Minnesota Legislature has directed Minnesota utilities to consider opportunities to purchase electricity from community based energy development (C-BED) projects. Minnesota Statutes § 216B.1612. A C-BED project is a wind energy project that is owned by certain individuals and organizations defined in the statute and that has the support of the county board where the project will be located. Minnesota Statutes § 216B.1612, subd. 2(f). C-BED generally refers to local landowners owning a renewable generation project, including but not limited to a wind project.

The Minnesota Department of Commerce is interested in promoting C-BED projects in the State of Minnesota. The Department has encouraged the utilities to undertake a study to determine how C-BED projects can be interconnected to the transmission system. Other interested parties, including the North American Water Office, have also requested that such a study be undertaken.

In the spring of 2004 a number of Minnesota utilities (Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, and Xcel Energy) in an agreement with the North American Water Office initiated a concerted effort to ensure that the transmission system in Minnesota was adequate to serve a growing demand for electricity and began conducting a number of transmission studies to identify constraints and determine what upgrades are necessary to increase transfer capability and improve reliability. These utilities have been coordinating this effort under the name CapX 2020.

In the fall of 2005 the CapX 2020 utilities committed to undertake an initial study to determine what transmission upgrades might be necessary to implement C-BED projects in Minnesota. The study would focus on a small geographic area of the State and would determine how certain amounts of megawatt generation scattered throughout the area might impact the transmission grid. The CapX 2020 group, with the concurrence of the Department of Commerce and the North American Water Office, determined that the West Central Transmission Planning Zone would be the area that would be studied. The West Central Zone consists of 17 counties and extends from the St. Cloud area to the South Dakota border.

Initially, the CapX planners identified all the substations in the West Central Zone and estimated each substation's maximum transfer capability. Simulations were run under 2009 summer peak conditions, with the addition of generation at each substation and a corresponding reduction in generation from various natural gas peaking units in Minnesota and Wisconsin, to identify potential transmission impacts. Presently, additional modeling is underway using a subset (defined by the study participants) of certain potential generation locations and certain amounts of C-BED generation to determine possible impacts on the transmission system.

II. Summary of Preliminary Results and Future Modeling

Because this overall study effort is at an intermediate stage, the information and data in this report are of an intermediate nature - they are not preliminary final results and it is not correct to use them as indicative of the final outcome of the complete C-BED analyses. The information in this report results from analyses that is, necessarily, constrained by assumptions used to manage the complexity of the analysis, the relatively narrow range of scenarios considered and limited types of analysis performed. These intermediate results could help guide the subsequent types of analyses to be undertaken.

There were 57 generation sites identified throughout the Zone, with a theoretical capacity of approximately 3500 megawatts. The initial modeling effort, ignoring voltage and reactive power issues and considering only thermal issues and with a number of assumptions described below, indicated that at 800 MW and at 1400 MW, significant impacts on the system occurred. The study participants have determined that it would be worthwhile to conduct further modeling at the 800 MW and 1400 MW levels and that work is presently underway.

III. Modeling and TLTG Study Assumptions

A. Base Model

The models used in this study originated from the 2003 North American Electric Reliability Council (NERC) Multiregional Modeling Working Group (MMWG) 2010 summer peak model building efforts. The Mid-Continent Area Power Pool (MAPP) regional data of the NERC model was replaced with modeling information from the 2009 summer peak model developed by MISO for (TSR) studies derived from the 2004 MAPP model series. The models used for this study are the same models as those used in Phase 2 of the Big Stone II delivery service (system impact) study.

These models represent the expected load and system topology for 2009 summer peak conditions. The models include the Big Stone II transmission facilities as well as the transmission facilities identified for 825 MW of outlet capability from southwest Minnesota. However, the Buffalo Ridge Incremental Generation Outlet (BRIGO) and the Southwest Minnesota to Twin Cities Extra High Voltage (SW MN TC EHV) transmission developments are not included in this model. Table 1 identifies the Big Stone II and 825 MW facilities that were included in the model.

Big Stone II Interconnection Facilities		
From	To	Voltage (kV)
Big Stone substation (Big Stone, SD)	Western Morris substation (Morris, MN)	230 kV
Big Stone substation (Big Stone, SD)	Western Granite Falls substation (Granite Falls, MN)	230 kV
825 MW Facilities		
From	To	Voltage (kV)
Split Rock (Sioux Falls, SD)	Lakefield Jct. (Near Jackson, MN)	345 kV
Lakefield Jct. (Near Jackson, MN)	Fox Lake (west of Fairmont, MN)	161 kV
Nobles Co. (Near Worthington, MN)	Chanarambie (east of Pipestone, MN)	115 kV
Buffalo Ridge (south of Lk Benton, MN)	Brookings County (White, SD)	115 kV

Table 1: Big Stone II Interconnection and the 825 MW Facilities.

B. Generation Modeling

The first step in the study was to identify each substation in the West Central Planning Zone. The West Central Transmission Planning Zone consists of 17 Minnesota counties: Benton, Sherburne, Wright, McLeod, Renville, Meeker, Kandiyohi, Stearns, Pope, Douglas, Grant, Stevens, Swift, Chippewa, Lac Qui Parle, Big Stone, and Traverse.

Once the substations were identified, it was necessary to determine the amount of C-BED generation capacity to allocate to each of the substations. A new generator was modeled at each connection point between the high voltage (> 115 kV) and low voltage (69 kV, 41.6 kV, etc.) transmission system. The methodology used to estimate the capacity depended on whether the substation was operated in a "closed-through" (or looped) configuration or in a normally open (or radial) configuration.

For "closed-through" substations, the size of the new generator was determined by taking 70% of the power flow through the step down transformer in the base case 2009 summer peak model plus the nameplate transformer capacity. For normally open switch substations, the size of the generator was determined by taking 70% of the base case 2009 summer peak load on the low voltage transmission system plus the nameplate transformer capacity of the step-down transformer.

Once the generation size and location were determined, a generator was added to the base case study model at each high voltage transmission bus that served the low voltage transmission system (as noted above). Using this methodology for the West Central Planning Zone resulted in 57 new generators ranging in size from 1 MW to 370 MW with a total generation of approximately 3,500 MW.

C. TLTG Analysis

The first study effort involved what is called a TLTG (transmission interchange limit analysis activity) analysis. This analysis is part of a software package developed by Power Technologies International (PTI) called Power System Simulator for Engineering (PSS/E). A TLTG activity analysis is a linear analytical tool that ignores voltage and reactive power issues and reports potential loading violations at any given transfer level for system intact conditions and under contingency conditions.

As such, this type of analysis doesn't present a complete picture, but is a screening tool that can provide direction for future detailed studies.

A TLTG analysis estimates the transmission interchange limits of a user-defined subsystem while applying single contingencies. In essence, generation (a defined number of C-BED MW) is added to the system at various points (a particular substation) while an equal amount (MW) of existing natural gas generation in Minnesota is displaced. Once the amount of new generation added to the system exceeded the existing amount of peaking gas generation in Minnesota, additional generation in eastern Wisconsin was then reduced in order to study the full 3500 MW of new generation throughout the West Central Zone.

1. Results

Results from the linear (TLTG) analysis in this study are shown in two different formats. These formats are tabular and graphical. The tabular format is used to display complete results including Transfer Level, Constraint, Owner, Outage, Limiting Element, Remedy, Quantity, estimated Incremental Costs and estimated Cumulative Costs. This format is well suited for reviewing constraints for validity. It is also the basis for the other formats. However, this format is quite lengthy which can lead to difficulty in quickly reviewing and finding break points in transfer levels that may warrant further study. For general viewing, a graphical representation provides a better means of displaying data in a meaningful way. From this format it is relatively easy to pick out constraints as well as the estimated cost associated with relieving the constraints. The graphical map format is useful for getting an overall view of where constraints or groups of constraints are occurring.

Due to limitations in the TLTG activity, the analysis of the transfer of 3,500 MW from the west central zone first to all of the existing Minnesota-based gas-fired generators and then to some of the eastern Wisconsin coal generators requires two different TLTG analyses. First, a TLTG analysis was performed with the incremental increase in C-BED generation being sunk to a reduction of Minnesota-based gas-fired peaking plants. This analysis allowed C-BED generation to be increased from 0 MW to 1,907 MW. From this point, the 2009 summer peak base case model was modified to bring the new C-BED generation within the case up to 1,907 MW with a corresponding reduction of the gas-fired generators to 0 MW. This step created a new starting case in which a second TLTG analysis was performed that sunk the remaining amount of C-BED generation (from 1,907 MW to 3,500 MW) to existing eastern Wisconsin coal generation. This second TLTG analysis allowed C-BED generation to be ramped up to its maximum level of 3,500 MW.

Figure 1 displays the estimated Installed Costs vs. Transfer Level for the Step 2 TLTG analyses. On this figure there are three lines. First, the blue line represents the

TLTG analysis from 0 MW to 1,907 MW. The purple colored line represents transfer related constraints resulting from the TLTG analysis from 1,907 MW to 3,500 MW. The green line represents a summation in estimated costs vs. constraints of the two individual TLTG analyses.

Figure 2 is a graph of the green line focusing on transfer levels from 0 MW to 1,500 MW.

This graph only contains estimated costs associated with positive transfer level constraints. All existing constraints identified on the system were ignored for this analysis. The two breakpoints where AC contingency analysis will be performed are also identified on this graph.

Appendix A-1 contains the tabular list of contingencies from the Step 1 TLTG analyses.

Information developed in the study so far disregards impacts on the lower voltage transmission system (41.6 kV and 69 kV) as well as generation interconnection and delivery facilities.

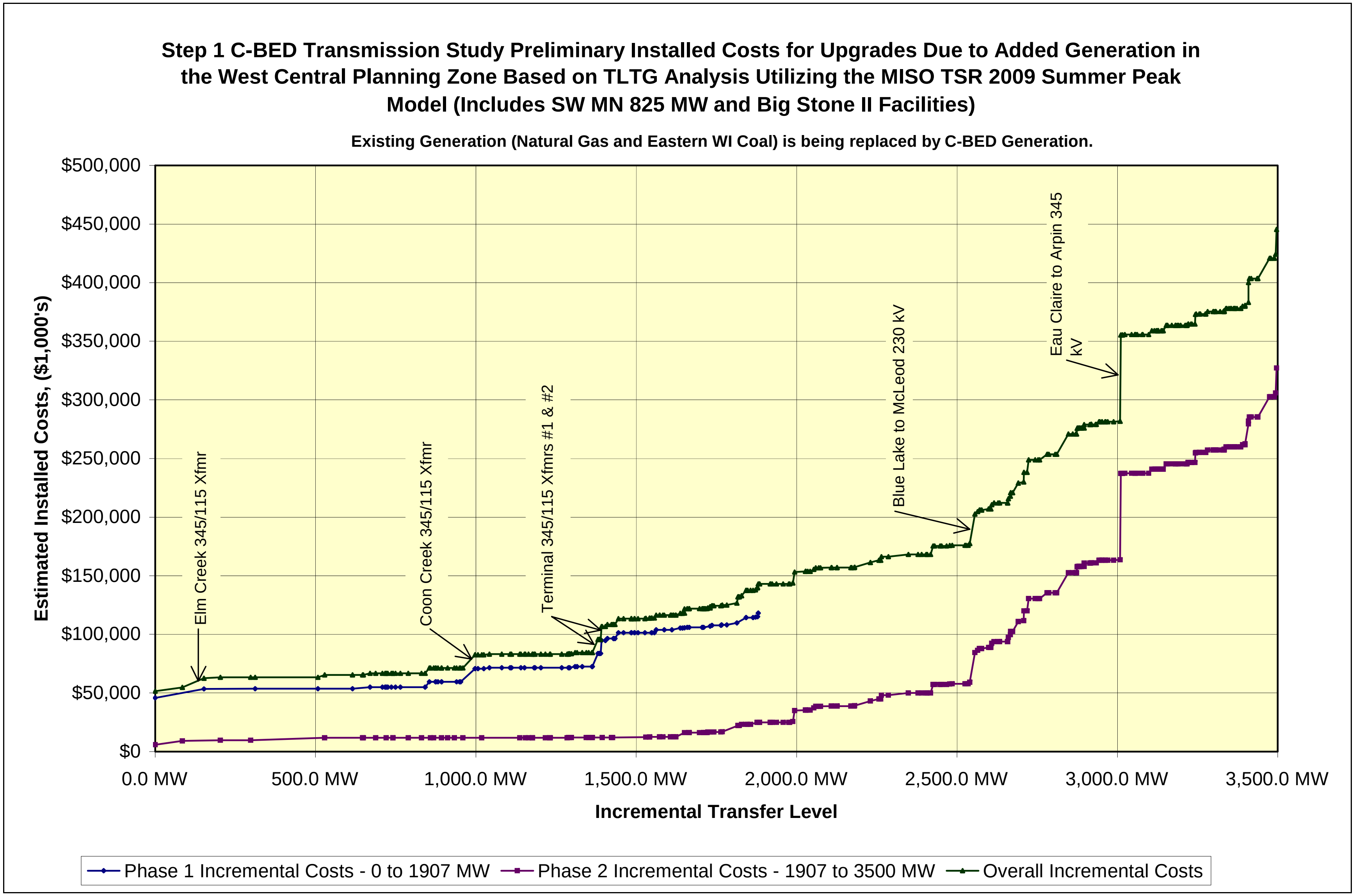

Figure 1: Results of the Step 1 TLTG Analysis from 0 MW to 1,907 MW and 1,907 MW to 3,500 MW.

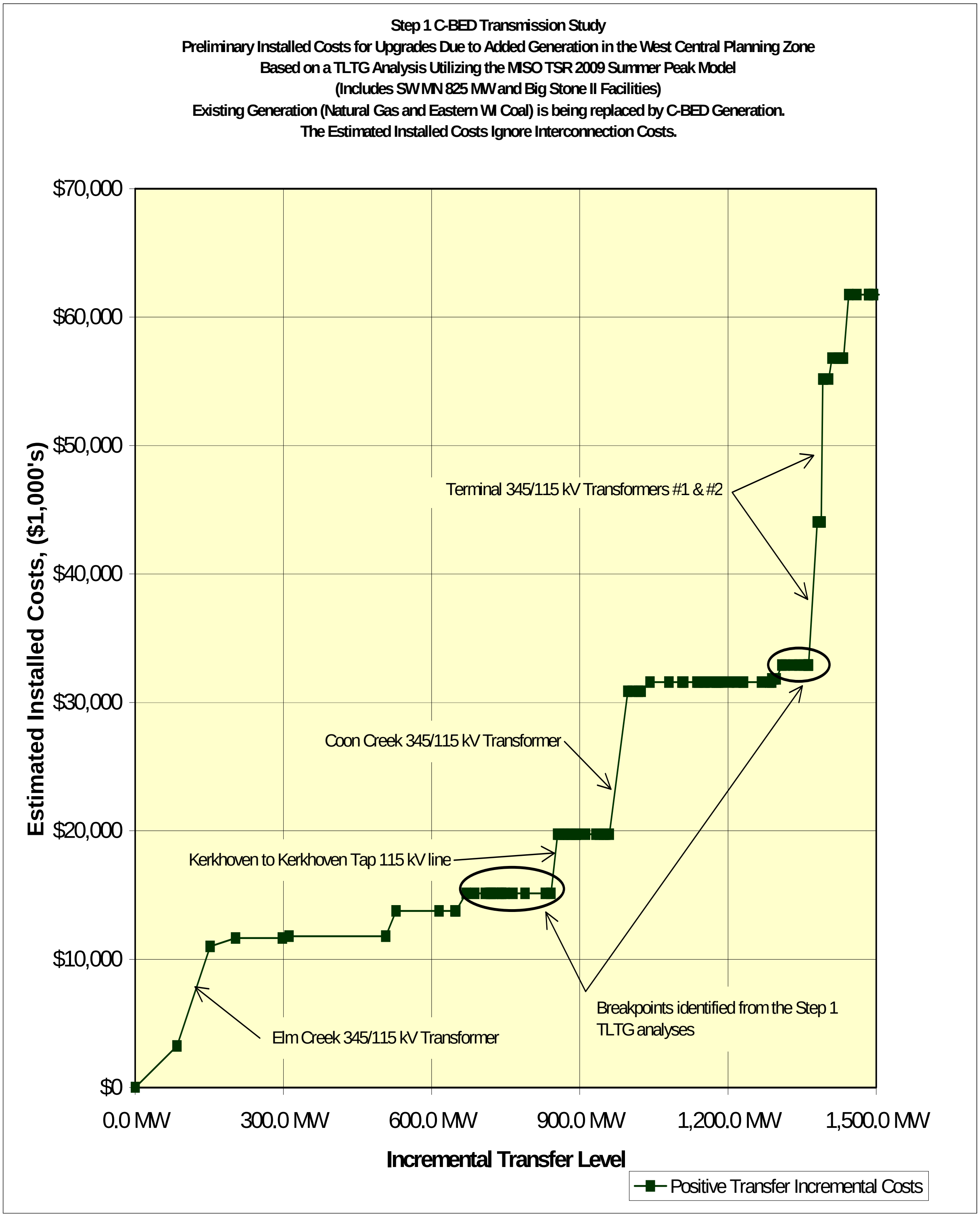

Figure 2: Step 1 TLTG analysis from 0 MW to 1,500 MW with Breakpoints for AC analysis Identified.

IV. Modeling and ACCC Assumptions

A. Generation Modeling

To more accurately model the C-BED generation locations and sizes at the 800 MW and 1,400 MW levels, generation locations from Step 1 were modified. In Step 1, all C-BED generation locations were assumed to have increasing generation development at comparable levels (all generation was ramped up at the same rate). In Step 2, C-BED generation locations and sizes were altered to assume more generation would develop at busses in areas with higher wind availability versus those areas with less wind availability. Table 2 contains a list of the revised locations for the C-BED generators used in this analysis.

B. TLTG and ACCC Analysis

Since assumptions about the size and location of the C-BED generation changed in this step, it was necessary to re-run the TLTG analysis up to the 1,400 MW generation level to insure that the change in modeling assumptions for the location and size of C-BED generation didn't have adverse or unexpected effects on the results obtained from Step 1. The results of the TLTG analysis were consistent with the initial TLTG results from Step 1 (defined break points at 800 MW and 1,400 MW), so the new C-BED generation assumptions for the Step 2 analysis were used for the AC contingency analysis. Figure 3 is a graph of the second TLTG analysis (pink) compared to the first TLTG analysis (green).

The results from the TLTG analysis indicated two break points that had expensive upgrades necessary for achieving the next increment of transfer out of west central Minnesota. These breakpoints seemed like logical C-BED generation levels in which to perform an AC contingency analysis. These breakpoints occurred at C-BED generation levels of approximately 800 MW and 1,400 MW. A base case AC contingency analysis with no C-BED generation will also be performed as a benchmark.

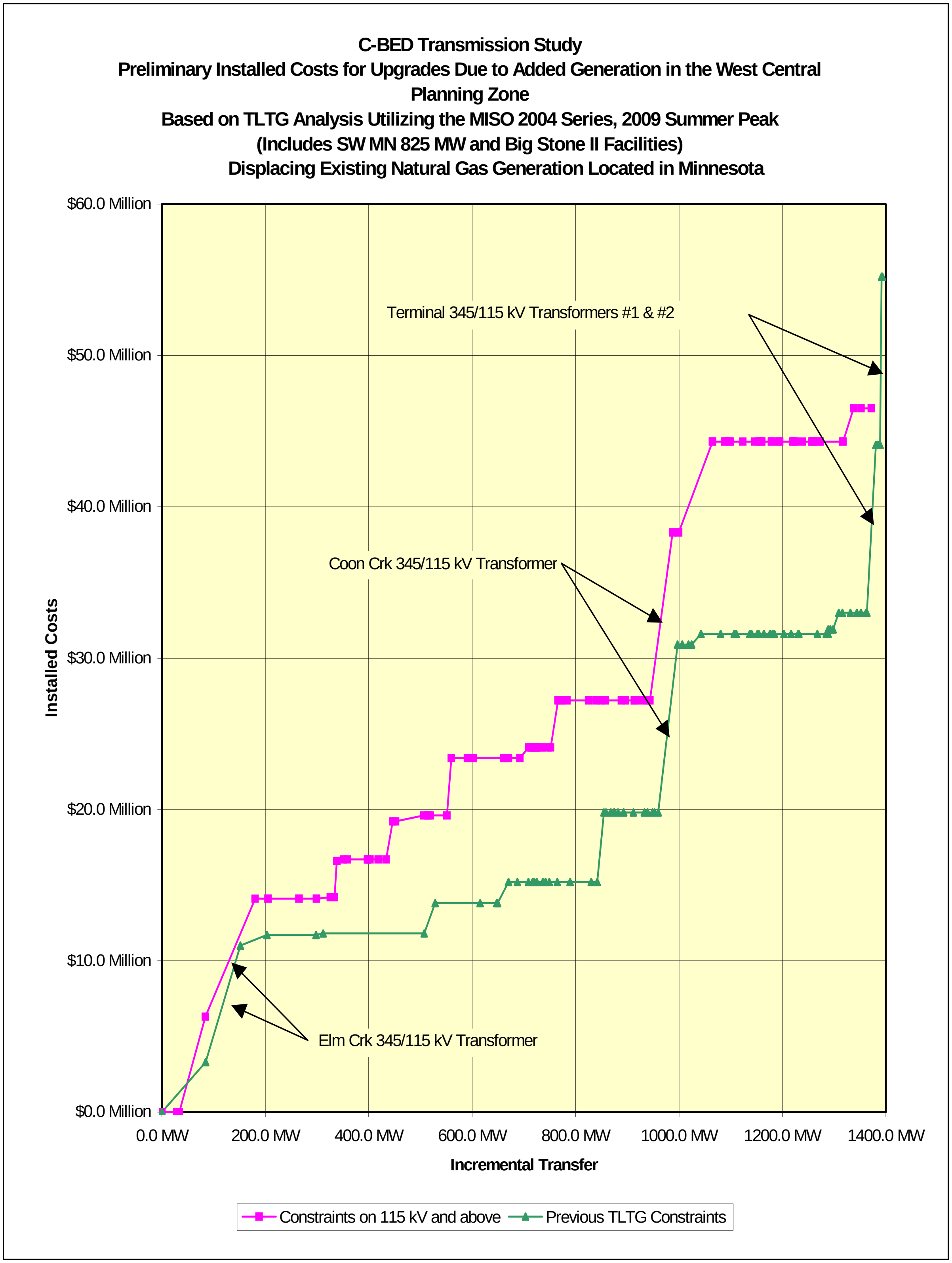

Figure 3: Results of the Step 2 TLTG from 0 to 1,400 MW compared with the Step 1 TLTG Results.

As stated in the introduction, the second step of this study involves completing an AC contingency analysis at discrete generation levels as determined by the results of Step 1. AC contingency analysis is a non-linear analysis that includes voltage and reactive power requirements of the system. This is a computationally intensive process that requires extensive amount of time (hours) to complete. Since this analysis must assume a discrete generation level to study, this is a very time consuming process if each scenario or transfer level was chosen to be analyzed with the AC contingency analysis technique. For this reason, TLTG analysis, a linear analysis that requires far less time to run (minutes), was used as a screening tool in order to find the generation levels to simulate the AC contingency analysis.

The AC contingency analysis will be performed using the Great River Energy (GRE) Contingency Program. This non-linear contingency program was written by GRE and performs a similar analysis as the PSS/E activity ACCC (AC Contingency Calculation) but provides better result reporting features. This program utilizes PSS/E powerflow cases and critical contingencies on the transmission system. This program is able to utilize historical switching procedures for specified contingencies, which make it a superior tool to the PSS/E ACCC activity. Since the results of the Step 2 TLTG analysis were similar to those obtained from Step 1, the base case, an 800 MW and a 1,400 MW transfer level will be the levels of C-BED generation to be analyzed during contingency analysis.

Bus#	Bus Name	County	Maximum CBED Generation Available	Generation Scenario	
				800 MW	**1,400 MW**
60161	'STREGIS7'	Benton	134 MW	57 MW	134 MW
60690	'MNARDTP8'	Chippewa	53 MW	53 MW	53 MW
60742	'PANTHER8'	Renville	107 MW	50 MW	107 MW
60749	'DGLAS C8'	Douglas	80 MW	80 MW	80 MW
60760	'PAYNES 8'	Stearns	155 MW	50 MW	155 MW
60763	'PULASKI8'	Wright	107 MW		27 MW
62002	'WALDEN 7'	Stevens	33 MW	33 MW	33 MW
62004	'GRACEV 7'	Big Stone	42 MW	42 MW	42 MW
62297	'BENTON 8'	Benton	112 MW		112 MW
62427	'WILLMAR8'	Kandiyohi	272 MW	30 MW	170 MW
62617	'BIGSWAN8'	Meeker	65 MW	50 MW	65 MW
62986	'HUTCHMN8'	McLeod	117 MW	50 MW	117 MW
63113	'MARIETT9'	Lac Qui Parle	11 MW	11 MW	11 MW
63217	'APPLETN7'	Swift	52 MW	52 MW	52 MW
63218	'MOROTP 7'	Stevens	21 MW	21 MW	21 MW
63220	'ELBOWLK7'	Grant	48 MW	48 MW	48 MW
63222	'ALEXAND7'	Douglas	48 MW	48 MW	48 MW
63225	'WHEATNS7'	Traverse	15 MW	15 MW	15 MW
66318	'MORRIS 9'	Stevens	28 MW	28 MW	28 MW
67454	'ALEXPLDM'	Douglas	40 MW	40 MW	40 MW
67455	'BRANDN 9'	Douglas	42 MW	42 MW	42 MW
			1,582 MW	**800 MW**	**1,400 MW**

Table 2: Revised List of C-BED Generation Sources Used in Step 2.

V. Conclusions

As study results become available, they will be posted on the CapX website (www.capx2020.com). Conclusions based on these study results are premature, given that the study has not been completed and results have not been finalized.

A. Schedule

The results of the ACCC analysis are expected to be available by August 2006. The CapX utilities will make a presentation to the Minnesota Public Utilities Commission in September or October 2006 on the results of that analysis.

VI. Future Studies

The Study of the West Central Planning Zone will not actually determine what the effect a specific C-BED generator will have on the transmission system. Any person proposing to construct a small generator in the West Central Planning Zone will be required to conduct an interconnection study to determine what transmission upgrades may be required to interconnect the generator to the transmission system. An interconnection study is a requirement imposed by the Midwest Independent Transmission System Operator (MISO).

The CapX utilities anticipate that upon completion of this study for the West Central Zone, there will be a greater understanding of what additional analyses are warranted.