

2004 ATC Access Study Initiative

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Executive Summary - Access Value Case

In response to customer input, emerging regional energy markets, and customers' desires to access and participate in these markets, American Transmission Company (ATC) launched an Access Study Initiative for 2004. This initiative is undertaken in conjunction with and in addition to regular ATC public planning process activities, presented in ATC's 10-Year Transmission System Assessment reports issued every six months. The purpose of this initiative, which will solicit and incorporate customer and stakeholder participation, is to 1) Assess the potential benefits and costs of improving the transfer capability of the ATC transmission system, and 2) Develop the value case for pursuit of future projects designed to increase transmission system access. Introductory materials regarding this initiative were presented to ATC customers and stakeholders in April 2004. All initiative materials will be posted to the ATC OASIS as developed and released.

This white paper outlines the various components of the 2004 Access Initiative Study and will be updated with details as the study proceeds and is further developed in response to feedback and findings. ATC is in the process of assessing and obtaining customer and stakeholder input on the potential benefits, costs, and impacts of improving access, and the elements that should be considered as part of the access "value case." In prior 10-Year Assessment reports, ATC has presented various discussions on the access/transfer capability topic, including most recently, examples of projects that might be considered to achieve various access objectives along with an estimated construction cost for those alternatives. Monthly meetings are scheduled throughout the summer to maintain contact with the stakeholders, as well as to provide regular status updates on the various components of this study effort as it proceeds. By the end of 2004, ATC intends to propose an access "target" that balances the costs and benefits of improved access on the ATC transmission network. A more detailed timetable is included at the end of this document.

There are several readily identifiable benefits to improving transmission access, including mitigating chronic limits to power transfers, lower overall energy costs for customers, reduction in system losses, improved reliability, improved operating flexibility, and other strategic benefits. There are also readily identifiable costs and impacts associated with improving access, including construction costs and the societal impacts of new transmission facilities, including environmental impacts.

Chronic limits

Removing historical and projected chronic limits on the transmission system can reduce anticipated generation redispatch, permit greater number and frequency of transactions from outside the ATC footprint, and allow more intra-ATC transactions to occur. ATC will identify historical chronic limits by data-mining the OASIS and NERC TLR logs. ATC will identify projected future chronic limits using power flow analysis and through Security Constrained Economic Dispatch (SCED) software simulations.

Economic

Access to lower-cost power both outside and within the ATC footprint can lower the total cost of energy. Savings can be attained through traditional bilateral energy transactions or through participation in a Locational Marginal Price (LMP) market. ATC has acquired LMP software (ProMod) that will be used for this analysis. ProMod simulates thousands of hours over the course of a year. Each hourly snapshot is the result of a SCED, utilizing generator production cost information as well as transmission constraints (flowgates).

Losses

Through the physics of power transmission, energy is lost continuously in the transmission system as power is transmitted from generators to the end use customers. This “extra” energy must be produced by generators, resulting in additional costs to customers and added emissions released from those generators. Transmission system losses that occur during peak load periods also add to the amount of generating capacity that utilities must install to meet peak demand. Transmission system expansion that will result in reduced transmission losses is desirable due to the economic and environmental benefits. Access projects being evaluated by ATC would lower transmission system losses and thus result in less energy and air emissions produced and require that less generation be installed. Transmission system loss analyses will be conducted to estimate the reduction in system losses and the resultant energy and capacity cost savings.

Reliability

Improved access can increase reliability by permitting additional help from outside the ATC system during emergencies. Consequently, improved access could potentially reduce reserve margin requirements. A Loss of Load Expectation (LOLE) analysis will be performed on each of the alternative cases. In addition, we will calculate the reserve margin required for each case to maintain an LOLE of 0.1 days per year (a.k.a. “1 day in 10 years”).

In addition, an Expected Unserved Energy (EUE) analysis will be performed on each of the alternative cases. The EUE software conducts power flow contingency analysis and utilizes outage statistics to perform a probabilistic measure of the ability of the transmission system to serve load under a variety of scenarios.

Strategic

There are various strategic advantages associated with expanded transmission access. Depending on the size and location of the new facilities, the ability to serve new customers and access new markets, including renewable resources, may be created. Sufficient backbone transmission infrastructure is necessary to support load growth and economic development. These and other strategic attributes of access projects will be identified, explored, and assessed for each alternative access scenario.

Operating flexibility

A robust transmission system provides additional flexibility to perform both transmission and generation maintenance outages and maintain reliable service under multiple

contingency scenarios. Operating flexibility enhancements enabled by alternative access scenarios will be assessed.

Construction costs

Building new transmission facilities requires significant investment. The price of materials, labor costs, right-of-way costs, and regulatory approval costs must be considered in the cost of access. ATC's experience on a number of recent projects will provide relevant costs for benchmarking.

Societal impacts (including environmental)

Although difficult (impossible?) to quantify in dollars, the societal and environmental impacts of new transmission facilities need to be identified and assessed as well.

Other

Several other factors have been suggested for inclusion in the access initiative. Although important on their own, they are not all directly related to the objectives of the access initiative. For completeness, they are listed here with a short discussion:

Demand side solutions, efficiency initiatives, impacts of changing fuel costs, support for new generation additions, support for bulk load additions and potential environmental regulations on generation portfolio: This study is evaluating the "big picture" of transmission and generation, but it is not intended to determine the appropriate mix of supply side or supply side and demand side solutions. Rather, this study presumes the appropriate mix is already planned for and is used as the base assumption for planning the future transmission system. Furthermore, the scenario analysis will attempt to capture the robustness of the system to meet a subset of potential future scenarios.

Seams: There are significant seams issues with adjacent control areas, reliability councils and market operators. This study makes the simplistic and optimistic presumption that seams issues will be addressed in the near future and that the entire market will operate smoothly by 2012.

Chronic Limits (current, historical & future)

Elimination of historical limits is an obvious first step towards increasing access. Many of the historically identified limits have either already been “fixed” or there are “fixes” planned in the near future. Experience shows that there are sometimes related limits “just around the corner”; careful analysis will identify these limits so that we can ensure that full utilization of the access target can be achieved.

ATC has three projects related to the identification of chronic limits: 1) Demonstration of historical and future Wisconsin Upper Michigan Systems (WUMS) import Total Transfer Capability (TTC) using Mid-America Interconnected Network (MAIN) Transmission Assessment Study Group (TASG) methodology. 2) Identification of the most limiting flowgates based on the Midwest Independent transmission System Operator (MISO) Open Access Same-time Information System (OASIS) Transmission Service Request activity. 3) Identification of the most limiting flowgates based on North American Electric Reliability Council (NERC) Transmission Loading Relief (TLR) activity that directly affects ATC customers.

Demonstration of historical and future WUMS import TTC

Attachment (WP1) summarizes historical and future WUMS import Total Transfer Capability (TTC). The analysis utilized MAIN TASG study data and study methodology. The future WUMS import TTC projections are based on projects currently proposed in the 2003 ATC Ten Year Assessment. These import TTC projections will be updated as projects are finalized for the 2004 ATC Ten Year Assessment. Please note that the MAIN TASG study methodology calculates import capability for reliability purposes and is not necessarily the same as commercially available transfer capability. The simultaneous transfer directions are from the MAPP study region in the west and the ECAR/Northern Illinois/South MAIN study area in the south.

Study Assumptions:

The updated 2004 Model from the TASG was used for years 2005 through 2010 and loads in ATC were updated for the appropriate year. Dispatch and associated interchange for new/proposed units having a signed IA was altered to reflect service, which has been sold. Projects from the 2003 ATC Ten Year Assessment were included in the summer peak model based on their in service year identified in the 2003 ATC Ten Year Assessment. Base transfers from WSCC and ALTW are included in the MAPP to WUMS FCTTC. Base transfers from all other areas are included in the EC/NI/SM to WUMS FCTTC. The distribution of power flow across an overloaded transmission facility for the transaction studies must exceed 3% to be considered a contributor to an overload. A linear relationship was assumed between transfer limits common to WUMS imports from the west and south.

See Attachment (WP2) for a list of projects that were included in the models subsequent to the 1999 summer peak.

Identification of Chronic Limits based on MISO OASIS TSR activity

Attachment (WP3) summarizes the most limiting flowgates based on MISO OASIS Transmission Service Request (TSR) activity.

Seller Comments and Study Comments for all OASIS requests with Point of Receipt (POR) or Point of Delivery (POD) in ATC and intersecting any part of the year 2003 were parsed to retrieve flowgates that were the reason provided for a refused TSR. Total energy of the request was computed and used to determine each control areas' top ten chronic limiting flowgates. A chart showing the amount of energy that was refused by flowgate for each month of 2003 illustrates the impact of each of these chronic limiting flowgates on a month-by-month basis. Each chronic limiting flowgate is correlated to 1) A fix that has already been constructed and placed in-service, 2) A fix that is expected soon, or 3) A potential future fix.

The chronic limiting flowgate charts were updated for 2004 year-to-date as of the end of June 2004 (WP4).

Identification of the most limiting flowgates based NERC TLR activity

This project will combine Transmission Distribution Factor (TDF) data and TLR information available from NERC to identify flowgates that have impacted the availability of transfer capability for each of the WUMS control areas (CA).

Beginning 1/1/2004, the current hour TDFs have been collected from the NERC FTP site. Through 3/15/04 approximately 75% of the hourly data has been collected. Due to a problem with a changed password in the scheduled FTP process, there was a 2-week period where the data was not collected. Excluding the 2-week period, approximately 93% of the hourly data has been collected. Data for the last collected hour will be used as a proxy for the hours where collected data is missing.

Each hour, about 5 MB of data is collected that breaks the data down by TDF, flowgate, control area, etc. The files need to be processed to extract only the needed information. To save storage space, the NERC data is stored on a Flowgate to Reference basis. To get the net TDF for a direction requires a simple mathematical combination of factors. The data will be processed to reduce the factors to a selected set of systems (control areas). The data will be further compared against the NERC TLR log to utilize only the factors for the activity associated with TLR level 3A or higher.

After making the necessary data associations listed above, the data will be reduced to a set of active TDF's for selected test directions. Each direction will be evaluated based on the NERC 5% TLR threshold.

Base case development

The analysis presented in this section describes the process used to identify and model the five strategic proxy projects representing five potential directions for system expansion:

- South (Illinois)
- Southwest (Iowa)

- West (Minnesota)
- Northeast (Ontario)
- East (Michigan)

The proxy projects were developed based on various analyses performed since the release of the 2003 10-Year Assessment.

The cost estimates for these projects and the associated “next fixes” represent general screening level cost estimates. Cost estimates for new transmission lines assumed the use of single-circuit steel poles on new 150-foot rights-of-way. Cost estimates for facilities outside of the ATC footprint were calculated using the same assumptions or were based on preliminary conversations with the affected neighboring transmission owner. Detailed cost estimates for specific projects and routes may differ from these very preliminary figures.

The analysis was performed using a linear analysis tool in the Power Technologies, Inc. Managing and Utilizing System Transmission software. This software used industry-wide for transfer capability simulations. In this analysis, a transfer distribution factor was used to determine whether facility overloads are affected by increased power transfers from one of the directions above into the ATC service territory.

The transfer distribution factor impact cutoffs used in this analysis were:

- 3% for all facilities in the network analysis
- 3% for MISO-monitored single outage flowgates
- 5% for MISO-monitored no outage flowgates

A list of relevant impacts on MISO-monitored flowgates is supplied for each proxy project and the base case scenario (i.e. no strategic project added). Transfers were not examined on a control area to control area basis; therefore, the results obtained for specific source-sink pairs may be different.

The power flow model used in this analysis was developed from the Summer 2012 base case from the 2003 10-Year Assessment. For the first valid limit identified for each proxy project, an appropriate transmission solution was developed and the analysis was rerun with the solution implemented to determine the next limit. For each scenario, the first two valid limits were identified and solutions were developed to mitigate these limits. The final run for each scenario included the two transmission solutions, and the subsequent new valid limit was identified.

Key Assumptions

The base case contains all planning projects needed to mitigate Summer 2012 overload and voltage violations except as noted below. The import capabilities identified in this analysis are dependent on the inclusion of these projects.

The base case was modified to reflect updated information for load forecasts, control area interchange and major transmission projects. One major project was eliminated from the model to avoid unduly biasing certain directions, and nine major projects were added to the base case power flow model. These changes include facilities required for confirmed

transmission service requests included in the model. The following facilities were either excluded from or added to the 2012 base case from the 2003 10-Year Assessment:

Transmission facilities excluded:

- West Middleton-Rockdale 345 kV line with a 345/138 kV transformer at West Middleton
- Duplicate Blount-Ruskin 69 kV circuit

Transmission facilities added:

- Second Wempletown-Paddock 345 kV circuit
- Weston-Central Wisconsin 345 kV line
- Rockdale-Lannon Junction 345 kV line
- Fox Energy Generation interconnected to the Point Beach-N. Appleton 345 kV line and Fox Energy-Forest Junction 345 kV line
- West Marinette-White Rapids 69 kV line conversion to 138 kV and White Rapids-Amberg 138 kV line rebuild
- Plains-Stiles 138 kV line rebuild
- Cranberry-Conover 138 kV line with a 138/115kV transformer at Cranberry
- Conover-Twin Lake-Iron River-Plains 69 kV line conversion to 138 kV and a 138/69 kV transformer at Conover
- Morgan-White Clay 138 kV line

Planned generation added:

Do we list the units going in this year (Riverside, Kaukauna, etc.)? (YES)

Port Washington (2005) – 600 MW

Fox Energy (2005) – 235 MW

Port Washington (2008) – 600 MW

Weston 4 (2008) – 500 MW

Elm Road 1 (2009) – 650 MW

Elm Road 2 (2010) – 650 MW

Total: 3,235 MW

Description of Representative Proxy Projects

The five projects examined in this section correspond to five geographic directions ATC could reasonably pursue for a new extra-high voltage (typically 345 kV) transmission interconnection. Only extra-high voltage projects were considered for the major projects in this analysis. However, ATC recognizes that extra-high voltage facilities are not the only alternatives available to meet future import requirements. Relevant alternatives to extra-high voltage facilities will be examined in the analysis performed for the 2004 10-Year Assessment.

The five representative proxy projects, as shown on the map in Figure VI-1 are:

1. **South:** Byron–North Monroe–West Middleton–North Madison 345 kV
2. **Southwest:** Salem–Spring Green–West Middleton–North Madison 345 kV
3. **West:** Adams–Genoa–Columbia 345 kV
4. **Northeast:** Sault Ste. Marie–Arnold 345 kV

5. **East:** Ludington–Forest Junction combined DC and 345 kV AC project
Project number 4 above would include either a DC tie or a phase shifting transformer at or near Sault Ste. Marie. However, for this analysis, the system in Ontario was not included in the model and the Sault Ste. Marie bus was modeled as an injection point for the transfers. For project number 5, a special source subsystem was created to mimic the DC sink and DC source points in the interconnected system.

Identification of flowgates associated with “local” constraints

In order to ensure that the ProMod analysis properly accounts for all constraining flowgates, we need to identify new flowgates based on planned enhancements to the transmission system, as well as to identify local flowgates associated with delivery of power to all control areas within the ATC footprint.

Linear transfer analysis modules of the Managing and Utilizing System Transmission (MUST) program from Power Technologies, Inc (PTI) will be used to detect the limiting flowgates for each given solution and scenario. The Transfer analysis will be performed from the following source and sink Control Areas and Zones:

Source Control Areas

1. ATLE – Alliant East
2. MGE – Madison Gas and Electric
3. UPPC – Upper Peninsula Power Company
4. WE – We Energies
5. WPS – Wisconsin Public Service Corp.
6. CE – Commonwealth Edison (Exelon)
7. NSP – Northern States Power (Xcel Energy)
8. ALTW – Alliant West
9. MECS – Michigan Electric Coordinated System
10. DPC – Dairyland Power Cooperative

Sink Control Area

1. ATLE – Alliant East
2. MGE – Madison Gas and Electric
3. UPPC – Upper Peninsula Power Company
4. WE – We Energies
5. WPS – Wisconsin Public Service Corp.

Sink Zones

1. MPU – Manitowoc Public Utilities
2. ESE – Edison Sault Electric
3. WPPI – Wisconsin Public Power Inc.

Participating Generators

Coal or Nuclear Generating Sites that have a single generating unit larger than 250 MW will be excluded from the sink subsystem for the purpose of detecting new flowgates. The following list of Generators will be excluded from the Sink subsystems:

1. Columbia – ALTE, MGE and WPS
2. Pleasant Prairie Unit #1 and #2 – WE
3. Kewaunee – ALTE and WPS
4. Point Beach Unit #1 and #2– WE
5. Weston Unit #3 and #4 – WPS
6. Oak Creek Unit #5, #6, #7 and #8 – WE
7. Edgewater Unit #4 – ALTE and WPS
8. Edgewater Unit #5 – ATLE and WE
9. Oak Creek Unit #1 – Phase One - WE

Offline units will be available for use in the Source Subsystem Modeling.

Models

In order to capture as many potential new constraining flowgates as possible, models will be constructed to represent the expected topology, load levels and anticipated imports of the ATC Transmission System in the year 2012. Load levels will be varied to represent different transmission flows for each of the selected scenarios. The load levels will be varied as follows:

1. Summer Peak
2. 80% of Summer Peak
3. 60% of Summer Peak

The selected scenarios that will be analyzed are as follows:

1. Basecase + Fix 1 + Fix 2
 - a. Fix 1: Rebuild of Lore – Turkey River – Cassville – Nelson Dewey 161 kV
 - b. Fix 2: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV Transformer at Town Line Road
2. Byron – North Monroe – West Middleton – North Madison 345 kV + Fix 1 + Fix 2
 - a. 345/138 kV Step Down at North Monroe
 - b. 345/138 kV Step Down at Weston Middleton
 - c. Fix 1: Des Plaines – Lombard 345 kV line rating increase
 - d. Fix 2: Monroe – Council Creek 161 kV – Relieve Eau Claire – Arpin Voltage Stability Limit
3. Salem – Spring Green – West Middleton – North Madison 345 kV + Fix 1 + Fix 2
 - a. 345/138 kV Step Down at Spring Green
 - b. 345/138 kV Step Down at West Middleton
 - c. Fix 1: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV Transformer at Town Line Road
 - d. Fix 2: Des Plaines – Lombard 345 kV line rating increase

The following scenarios will give consideration to including the Rockdale – West Middleton 345 kV line in the models and will be analyzed in the future:

1. Adams – Genoa – Columbia 345 kV + Fix 1 + Fix 2

- a. 345/161 Step Down at Genoa
- b. Fix 1: Rebuild of Lore – Turkey River – Cassville – Nelson Dewey 161 kV
- c. Fix 2: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV Transformer at Town Line Road
2. Ludington – Forest Junction DC Tie + Fix 1 + Fix 2
 - a. A DC tie across Lake Michigan from Ludington Pump Storage Facility to the Forest Junction Substation
 - b. Fix 1: Rebuild of Lore – Turkey River – Cassville – Nelson Dewey 161 kV
 - c. Fix 2: Installation of a third 345/138 kV Transformer at Forest Junction
3. Canadian – U.P. DC Tie with a 345 kV Terminal at Arnold Substation
 - a. A DC tie across at Sault Saint Marie connecting with Canada
 - b. Sault Saint Marie – Arnold 345 kV line
 - c. 345/138 kV Step Down at Arnold
 - d. Fix 1: Rebuild of Lore – Turkey River – Cassville – Nelson Dewey 161 kV
 - e. Fix 2: Installation of a second Paddock 345/138 kV transformer or installation of a 345/138 kV Transformer at Town Line Road
4. Prairie Island – North LaCrosse – Columbia 345 kV + Fix 1 + Fix 2
 - a. 345/161 Step Down at North LaCrosse
 - b. Fix 1: Unknown at this time
 - c. Fix 2: Unknown at this time

Economic Value of Improved Access (LMP, including losses)

The LMP analysis (see Attachment (WP5)) will be used to provide a present value revenue requirement (PVRR) comparison of the projects that includes the capital costs of and generator and transmission system operational cost differences between the projects. Generator operational costs include production cost (fuel, O&M). Transmission system operations costs include losses. Losses are inherently included in the hour-by-hour PROMOD simulation; they are handled similar to load, but are difficult to itemize.

Things to keep in mind concerning the accuracy of the analysis:

- We will begin by modeling only one year in PROMOD.
- We will be calculating the difference in cost between alternatives, most of whose input data is identical. Using the difference between alternatives tends to reduce the impact of any inaccuracies in forecasts and input data. Regardless, we intend to be diligent in reviewing the input data, especially that for the ATC footprint.
- This analysis represents the first review of the production cost and transmission model data for the ATC footprint used in PROMOD.

In addition to the PVRR comparison of projects, a summary table will be produced listing total ATC system costs, generation dispatch within ATC's footprint by technology and other leading indicators. A detailed analysis and comparison of the transmission

constraints between the projects will be based on the most frequently constrained and/or those that have the biggest financial impact.

Losses

Through the physics of power transmission, energy is lost continuously in the transmission system as power is transmitted from generators to the end use customers. This “extra” energy must be produced by generators, resulting in additional costs to customers and added emissions released from those generators. Transmission system losses that occur during peak load periods also add to the amount of generating capacity that utilities must install to meet peak demand. Transmission system expansion that will result in reduced transmission losses is desirable due to the economic and environmental benefits. Access projects being evaluated by ATC would lower transmission system losses and thus result in less energy and air emissions produced and require that less generation be installed. Transmission system loss analyses will be conducted to estimate the reduction in system losses and the resultant energy and capacity cost savings.

Although losses are inherently accounted for and included in the LMP analysis, we intend to differentiate the loss savings of the various alternatives for comparison purposes. For each of the projects, several base cases will be developed and losses tabulated: 100%, 80%, and 60% of peak; See Attachment (WP6).

Reliability Value of Improved Access

Loss of Load Expectation (LOLE)

LOLE is a probabilistic measure that is used to help determine whether sufficient power will be available at some specified point in the future to meet customer demand and to provide a guideline for setting reserve margins. Planners in the MAIN reliability region try to achieve an LOLE of 0.1 days/year or lower; if this LOLE is achieved then the study area should have enough power to meet demand such that a shortage of power (forcing the use of rolling blackouts) should occur no more than one day in ten years. To determine whether an area will achieve the LOLE criterion, the future power needs of the study area are compared against the power already available as well as the power that is relatively certain to become available either through new generation or new transmission that can import additional power. The computer model used to calculate the LOLE accounts for such factors as power plant forced outage rates and maintenance outages. Planners can then use the output from the model to help determine whether the area will have sufficient power to meet an LOLE of 0.1 days/year. If the calculations show that the area will not meet a LOLE of 0.1 days/year, then demand must be reduced and/or capacity must be increased to meet the LOLE criterion.

LOLE simulations will be run to determine the improvement in LOLE associated with each access alternative and to determine whether the LOLE criterion of 0.1 day annually is met for the base case (no access alternative) and for the five access alternatives.

Reserve Margin

As an additional benefit of increased access, it may be possible to reduce reserve margins required to meet the LOLE criteria of 0.1 days/year. LOLE analysis will be run iteratively to determine the reserve margin required to maintain the LOLE criteria of 0.1 days per year for the access alternatives.

Expected Unserved Energy (EUE)

Expected Unserved Energy will be computed to determine the improvement in EUE associated with each access alternative. The Physical Operation Margin and Optimal Mitigation Measure (POM & OPM) software from V&R Energy will be utilized for this analysis. The analysis utilizes the historic probability of contingencies along with the topology of the transmission system to determine how long and how much load may go unserved as the result of a transmission outage.

Line outage probabilities are derived from actual statistics from years 1997-2003. Actual line outages per hundred mile-years were calculated separately for each voltage class. Total reactance and total miles were calculated for each voltage class to convert outages per hundred mile years to outages per ohm-years.

Outages per year, or outage frequency, were calculated for each model branch as the product of that branch's reactance and outages per ohm-years. Actual line outage durations were calculated separately for each voltage class.

Each branch's outage probability is based on the product of its outage frequency and outage duration.

Strategic

Qualitative analysis of the various alternatives will be accomplished in collaboration with stakeholders. There are several considerations, including: potential to bolster economic development, access to renewable resources (including wind), providing geographic diversity within the EHV system and enhancing the value of other existing and planned components of the ATC system. The evaluation of these factors will be summarized in the decision matrix described below.

Operating flexibility

Although difficult to quantify on a case-by-case basis, we will work with ATC operations as well as various stakeholders to identify "other" benefits of additional access including maintenance flexibility.

Generator Stability

As a potential benefit of increased access, some of the existing stability issues on the ATC system may be reduced or eliminated. ATC will perform stability analysis to determine if any of the access alternatives impact existing stability issues.

Voltage Stability

Voltage stability analysis will be performed on the access alternatives to determine if voltage stability is more limiting than thermal (overload) or voltage constraints.

Construction Cost Estimates

For the initial screening, we will utilize the ATC's gross cost-estimating tool. In subsequent phases of preferred access alternatives, more detailed cost estimates will be obtained.

Environmental Impacts

High level screening of environmental impacts of the access alternatives will be performed and summarized in the final report.

Study Assumptions and Sensitivity Analysis

Study assumptions for the various components of the analysis are outlined above. In the interest of completing the study by the end of the year, we will perform limited sensitivity analysis. Engineering judgment will be applied early on to ensure that the sensitivity analysis could have a bearing on the final result.

Decision Matrix

Since not all benefits and costs are easily expressible in dollars, we will assemble a decision matrix ranking the various alternatives relative to each other.

Deliverables and Timetable

A number of the components of this study have never been performed, so it is difficult to pinpoint a number of dates for the deliverables. The intent is to provide monthly updates as to the status of the various components and have enough information available by September 1st, 2004 to endorse a target access level as well as a preferred alternative to accomplish the target. Attachment (WP7) contains additional details.