Attachment PE-B

Business Case Assessment for Power Electronics Opportunities for the Power Grid

TABLE OF CONTENTS

LIST OF FIGURES & TABLES

INTRODUCTION

In June, 2003, this study was initiated. The objectives of this study were several-fold:

- Analyze the value of power electronics (PE) in the transmission grid.
- Is further 'risk' investment necessary for R&D at this point, or should typical commercial players be at a point where they will 'run' with the new products?
- If further 'risk' funding is required, what are the most promising areas of R&D to undertake?
- What is the 'return on investment' for participants in the PE transmission grid investments and what metrics should be used?

This final report analyzes the primary business case opportunity of the pros/cons of investing in power electronic (PE) based technology within the electrical infrastructure of the power grid. This report also identified two related and important subsets for PE investment. Much of the identification process and the basis for the analysis were arrived after extensive interviews, research, and follow-up discussions with dozens of individuals within EPRI/CEIDS, over half of the June Washington DC Power Summit attendees, a business case presentation at the October 21st Annual FACTS Conference in Utica, NY, many utility members, actual FACTS site users (Flexible AC Transmission System), dozens of historical EPRI and other sub-contractor reports (e.g. Primen, ADL, etc.), all major PE vendors (Siemens, ABB, Alstom, and Mitsubishi as well as Silicon Power and Virginia Tech), as well as other consultants and experts in the field, and publicly accessible FERC utility filings, these opportunities were judged to be the most promising and worthy of more detailed follow-up with the appropriate players (e.g. CEIDS/E2I members, PAGs, targeted regulators, etc.). The purpose of this report is to encourage discussion within CEIDS, E2I, and its advisors to help identify and suggest, where possible, other follow-up efforts and analyses.

As part of this report, please find attached a set of revised Powerpoint presentation slides, half of which were used at the Utica, NY, FACTS conference. I have also included, where appropriate, related observations and recommendations, which might not have to do directly with the opportunities analyzed, but are quite relevant to the role that CEIDS and E2I are undertaking.

BACKGROUND

Although EPRI and more recently CEIDS/E2I have performed work within the power electronics (PE) field for over two decades (beginning with silicon-based thyristors and then more recently to voltage sourced converter based approaches), one of the significant challenges facing these efforts on performing further R&D and commercialization collaboration with potential utility and energy equipment companies is constructing viable business cases for some of the myriad possible applications of Voltage-Sourced switching Converters (VSCs) as applied to compensating and controlling T&D networks as well as potential end-use applications (e.g. distributed generation, DG, energy storage, SMES, fuel cells, etc.).

Some of the earlier T&D PE applications were initiated by EPRI and a number of U.S. and foreign utilities to solve voltage support and system stability problems and, thereby, allow higher utilization of the transmission system. Components based around SVCs are essentially mature products with well-understood applications and mature cost structures. Essentially, these components use the thyristor switches to couple to either capacitors or inductors to perform T&D VAR 'leading or braking' compensation, whereas converter based devices use the switching capability itself to provide this compensation. Today, there are about 800 SVC installations in transmission and distribution networks worldwide. Since only 20% of the costs of SVC-based products deal with the actual costs of power electronic semiconductors, there is little room for major cost reductions in this technology. Although SVC-based applications perform power system compensation and intersystem tie-ins well, they also have limitations which potentially provide electric utilities and their energy vendors long term opportunities to provide additional power grid capacity, control and compensation, reliability, availability, power quality, and performance.

These opportunities tie well into CEIDS's vision of "developing the science and technology that will ensure an adequate supply of high quality, reliable electricity to meet the energy needs of the digital society." PEs allow the power grid to be transformed from a purely 'passive' network to an increasingly 'active' network over time which intrinsically would be more reliable, higher capacity, more secure against natural and terrorists threats, and more economical. In general the application of PE to the power grid would provide the following benefits:

- Voltage Regulation
    - Improve power quality
    - Maintain voltage profile
    - Limit over-voltages
    - Prevent voltage collapse

- Power Flow Control
    - Eliminate bottlenecks
    - Improve power transfer capability
    - Minimize power loops

- Stabilize System Dynamics
    - Provide voltage stability
    - Provide transient and dynamic stability
    - Power delivery stability

- Improved Management and Control
    - Provides greater flexibility
    - Provides more versatility and multi-functionality
    - Near real-time information for monitoring/control
    - Provide increasingly more ‘synergistic’ benefits as FACTS nodes increase

One of the challenges is identifying and quantifying the respective ‘values’, both tangible and intangible, of these PE-based attributes.

Finally, another key element of CEIDS’s and E2I’s vision is the ‘self healing power grid’ that sees a powerful combination of ubiquitous sensors, real-time and forward projecting control and management, continuous power grid efficiency optimization, stability, and risk assessment. The primary objectives of the self-healing grid are: dynamically optimize the performance and robustness of the system; quickly react to disturbances in such a way as to minimize impacts; and effectively restore the system to a stable operating region after a disturbance.

In concert, all of these factors contribute to the new opportunities and benefits that advanced power electronics may provide to the T&D network of the future. These new power electronics offer enormous potential for reducing the complexity, size, weight, and cost of highly sophisticated, multifunctional controllers for T&D systems. Substantial financial and power quality benefits would be realized if the T&D network could be more closely operated toward its intrinsic thermal and upper stability limits and power flows directed through the network on a managed basis rather than strictly according to the basic physics of taking the least path of impedance through the multiple parallel electrical paths of the grid. With some further deregulation still likely to be implemented and as the ability to contract ‘buckets’ of electrical energy over specified periods of time increase (e.g. retail wheeling) and the desire to ‘transport’ more energy greater distances continues to increase, managing power flows and eliminating their associated ‘power-flow loops’ and ‘bottlenecks’ will become increasingly important. Advanced system management and controls will become increasingly important as power is managed within each of the four major U.S. regional power pools, and their many Independent System Operators (ISOs) and eventual Regional Transmission Operators (RTOs), T&D networks, power generators, distributors, and end-users.

Most of the advancement in PE components that can be utilized in T&D applications have been driven by previous advancements and higher manufacturing volumes associated with either the large traction drive or large variable speed motor controls industries. This was true for both the development of the silicon-based thyristor-controlled Static Var Compensator (SVC) in the late 1970s as well as the more recently developed GTO (gate turn-off) and IGBT/IGCT (insulated gate bipolar transistors) applications within VSCs. These transmission and distribution controllers employ self-commutated, *voltage-sourced switching converters (VSC)* to realize rapidly controllable, static, synchronous ac voltage or current sources. Indeed, the VSC can be considered as an “*electronic generator*” that is analogous to an ideal, rotating synchronous machine which generates a balanced set of (three) sinusoidal voltages at the fundamental frequency, with controllable amplitude and phase angle. It can internally generate *reactive* (both capacitive and inductive) power and can also exchange *active power* with the ac system if it is coupled to an appropriate energy source that is able to supply or absorb the power it supplies to, or absorbs from, the ac system. Furthermore, this electronic generator has no inertia, its response is practically instantaneous, and it does not significantly alter the existing system impedance. PE controllers can increase power transfer capability in some situations by up to 50% and, by eliminating power bottlenecks and loop power-flows, extend the market reach of competitive power generation and greatly reduce unnecessary incremental power losses and reduced transmission capacity due to power-flow loops. This translates into avoided new construction costs for T&D, more competitive markets, and more options for generators, distributors, and customers alike.

Additionally, from an applications standpoint, the VSC technology also offers the following operational features and user benefits:

- Uniformity and modularity (the same modularly constructed converter can be used for shunt and series applications, for voltage and power flow control)
- Convertibility and expandability (the transmission controller is functionally convertible, e.g., a shunt compensator into a series compensator or vice versa, and expandable, e.g., from a single-line controller into a coordinated multi-line controller system)
- Shunt and series compensation for voltage support and power flow control that can be maintained with depressed bus voltage (shunt) and wide range of line current variation (series).
- Unique capability to simultaneously control transmission voltage, impedance and angle or, alternatively, independently control active and reactive power flow.
- Unique capability to control and balance active and reactive power in a multi-line system.
- Unique capability to tie two or more systems synchronously or asynchronously (e.g. both AC or DC) with synchronizing torque and inherent terminal voltage support capability via controllable reactive (capacitive and inductive) compensation.
- Unique capability to couple energy storage to ac systems.
- Small physical size and potential for minimum installation labor (potential for factory assembly).

For purposes of this report, the silicon based thyristor (SVC) applications will be referred to as ‘**conventional**’ applications whereas the GTO/IGBT converter based applications will be referred to as ‘**new technology’** applications. Of course there are even more advanced integrated circuit technologies at various stages of either laboratory development or early product development including ETOs (emitter turn-off) and

SuperGTOs, SiC (silicon carbide), GaN (gallium nitride), and even diamond-based emitters. CEIDS is co-funding some of these even more advanced efforts.

To date, approximately twelve field tests have been initiated in the U.S. that utilize VSC-based applications, four within EPRI/CEIDS, and some outside of EPRI. The EPRI/CEIDS involved efforts have tested selected applications on both the transmission side (100 MVAr at TVA and 320 MVAr at AEP) and the distribution side (1 MVAr at AEP and BC Hydro) utilizing static synchronous compensators (STATCOM). The most advanced multiple purpose PE application is just now coming on line at NYPA using a multi purpose CSC (convertible static compensator designed for eleven functional modes of operation). Other potential applications involve the static synchronous series compensator (SSSC) and shunt compensators, the unified power flow controller (UPFC), the interline power flow controller (IPFC), the dynamic voltage restorer (DVR), and the back-to-back tie (BtB), in addition to several other variants. Because one of the applications of VSC technology is tying two asynchronous systems together, it can also be used in distributed generation (DG) to tie windfarms, fuelcells, photovoltaic solar panels, battery and other forms of energy storage (SMES), flywheels, and microturbines into the overall power grid. DG applications would be considered an ‘end-user’ VSC application, but one which is nevertheless very important to EPRI and electric utilities, in general, as DG will have profound impacts on the overall system characteristics of the power grid. DG is projected to potentially provide as much as 25% of the total generated power by the year 2020.

Given this broad more than two-decade participation of EPRI into the improvement and acceptance of Power Electronics for Transmission Grid applications, it could be concluded that ‘enough has been done.’ However, as has been outlined here in only the Background section, there are important technical and economic impacts that are still to be achieved by CEIDS’s continued participation. The following sections delve into some of these issues more deeply.

BUSINESS CASE 1:
Generalized Case for PE Investments in the Transmission Grid

Objective

The objective of this section is to provide a generalized economic analysis for investments in power electronics (PE) for the transmission grid. Ultimately, at least two approaches could be used to justify investments in the transmission grid: a generalized U.S. power grid-wide analysis (i.e. this report) or the traditional case-by-case analysis undertaken on an individual basis by a utility or transmission entity owner. As such this analysis is not meant to be a substitute for a specific business case applied to one particular transmission corridor or problem and all of its unique circumstances. Consequently, a more specifically applied business case would indicate that some component benefits and costs are higher and some are lower than those shown here in the generalized case discussed here. The analysis in this report has the objective of presenting the former approach of a U.S.-wide power grid analysis and leaves the unique case-by-case analysis to individual utilities which can draw upon the pros/cons of the generalized analysis presented here. One of the primary purposes of this analysis is to indicate that many facets of value and contribution of PE-based applications are not being adequately accounted for in a typical financial analysis. This section will begin with broad background descriptions of U.S. transmission grid facts and ‘symptoms’ that indicate some general trends toward deterioration of the overall power grid and then it will delve into a number of specific factors which each contribute to the overall financial value of PE investments in transmission.

U.S. Transmission Grid Overview

The U.S. transmission grid is the silent and ubiquitous backbone that keeps our everyday life going smoothly. There are many metrics by which it can be measured and sobering trends by which it has clearly lost ground over the last decade. The total value (2000 book value) of U.S. T&D assets is approximately \$360B, although in current dollars, it could be well over a trillion dollars. Over these T&D assets flow approximately \$250B/year of electricity (at retail). Power disruptions have been estimated to cost the U.S. economy as much as \$120B/year and individual power outages can total into the \$billions (e.g. the Western region outage in 1996 was estimated at \$2B and preliminary estimates of the August 2003 Northeast blackout have started at \$6B). Although these figures are open to some interpretation and could be lower ***or*** much higher, they still represent over 1% of the total U.S. GDP (gross domestic product). Economists and politicians get excited about 0.1% changes in the U.S. productivity rate and an improvement of 0.25% in the productivity rate is fantastic. Ironically, improvement in the national grid could directly contribute 0.25% or even 0.5% per year to national output which would be equal to approximately \$20-50B/year! – it begs the question: “What is that worth? And how can it be achieved? ”

Another important trend in U.S. transmission grid metrics has been the steady growth in digital and other more power quality sensitive loads. Currently 10% of delivered electric power is provided to ‘digital applications’ and is projected to grow to over 16% by 2011.

Additionally, T&D reserve capacity compared to electricity demand has consistently decreased by 15% over the last decade due to a variety of factors including environmental, rights-of-way, regulatory, social, and lack of direct financial incentives to make significant new investments, etc. Furthermore, by 2010, the projected T&D capacity growth is only 5% compared to the projected growth in load of 20% resulting in an additional shortfall of over 15%. These T&D shortages result in stress and overloads on the power system as demonstrated by the nearly 250% increase in transmission line relief requests (TLRs) from 1998 to 2002 (not including the 8/14/03 NE blackout). Blackouts are not limited to the U.S. either with over a half dozen major blackouts over the last year affecting such diverse areas as: all of Italy, most of Scandinavia, Saudi Arabia, Djakarta, large parts of Spain and Brazil, and others. Furthermore, over the last 5 years, the number of U.S. blackouts that resulted in more than 500,000 customers going black has increased by over 40% to almost 60. All of these metrics point out the great need for improving the U.S. power grid.

The Case for Power Electronics

Regarding power electronics (PE), since the U.S. load is still projected to grow at approximately 2%/year for the next decade (14,000 MW/year), this translates into over 4%/year of MVAR compensation which will be required. Although most of this reactive compensation can be obtained from traditional passive techniques, even a 10-20% VSC usage rate (justified according to many of the arguments presented in this report) still translates into an astounding $100-200M/year PE market for just the U.S. On a retrofit basis, the total U.S. grid represents a PE market in the range of $5-10B. These figures clearly indicate that from a business perspective, a sufficient potential market does exist for Power Electronics that can support multiple competitive vendors.

A compelling generalized case for Transmission investments can be made when all the contributing pieces and attributes are added together that clearly demonstrate that society and its constituencies would realize considerable cumulative benefits. The basic idea of this approach is that if it can be demonstrated that somebody (e.g. society) would gain substantially and that it is financially feasible (what this report hopes to demonstrate), then the only question that remains is what is the best way to ‘split’ the clear value so that all parties are incentivized to make it happen. The remainder of this sub-section will undertake to review this business case as well as the assumptions utilized in this generalized analysis and a description of each of the major categories of benefits and/or costs. The primary categories investigated include the following:

- Value of Energy (and additional internal power losses)
- Avoided Costs and Rights-of-Way and Capital Expenditures
- Enhanced Security, Reliability, and Power Quality
- Eliminate/reduce Power-flow Loops
- Other Tangible Benefits
- Environmental Benefits
- System Flexibility and Load/Generation Location Adaptability

- Other Intangible Benefits
- Synergistic Benefits ‘system-wide’ control rather than just ‘point’ control
- Transmission Value Proposition

ASSUMPTIONS OF ANALYSIS

Before the more detailed analyses is described, it is important to understand the implicit assumptions which were used as each of the categories were valued for economic benefits and costs. In order to evaluate, whenever possible, an apples-to-apples comparison, VSC attributes (both benefits and deficits) were translated into dollars. Where economic benefits were realized over time (such as energy savings (+) or additional O&M (-)), a discounted cashflow was performed. The key approach employed here was that all of these analyses have been performed on a ‘generalized’ transmission investment case. Consequently, any specific ‘case-by-case’ analysis of a given PE transmission investment decision would likely show some of these benefits/costs being too high or too low. For example, depending upon location and prior ownership, the imputed ‘costs’ associated with a right-of-way (ROW) for a transmission corridor could be much higher or lower than indicated here and the avoided costs of another transmission corridor can be much greater than indicated in this analysis. The primary assumptions of this analysis follow:

- All values are based on an incremental analysis from base case (e.g. incremental O&M, incremental capital expenditures, incremental power losses, etc.)
- End values are calculated from the perspective of what value is available for society or the final ‘end-customer’
- Projections look out 20 years with growth factors ranging from 3%/year (which is assumed to be the nominal inflation rate) to 10%/year depending upon a subjective judgment applied to the future importance of each factor (e.g. grid security). See Table 1 below for a list of these ‘inflation’ or growth adjustment factors
- The implicit discount rate was assumed to be 15% for calculation of Net Present Value Amounts (as a return on equity, ROE, threshold expectation by investors)
- Average retail energy value of $.08/kwh was utilized throughout
- High demand load factors were assumed at 20% duty cycle
- VSC reliability has been assumed to be equal/better than SVC (this must be demonstrated over next one to two years; see other sub-sections for more)
- System benefits subjectively assumed to be worth 5-10% of the total benefits over time
- VSC power losses assumed to be 0.5% greater than base case (these should improve over time)

- O&M costs for VSC applications assumed to be 50% greater (again this should improve over time)
- Cost differential between VSC and SVC assumed to be approximately 25% (see Table 3 for details and separate sub-section for more analysis)
- VAR dynamic response between VSCs and SVCs is equal when SVCs are 'over-rated' by 30%
- Typical transmission power losses assumed in the range of 2-4% of nominal power flow

It is important to point out that the discount rate has been set an implicit rate of 15% which has been an historical rate of return on equity (ROE) that shareholders in utilities might expect as a longer term 'fair or typical' return. Although this rate might be considered high at the present moment for utility stocks, it is believed that it still represents a reasonable proxy for returns over the next decade. Please note, that if the ROE were decreased it actually increases the value of future cashflow streams. All of the economic evaluation matrices using discounted cashflows can easily be rerun for lower or different discount rates. For example, decreasing the discount rate to 10% has the effect of almost doubling the net present value (NPV) of many cashflows because it intrinsically attributes increased value to future cashflows rather than current ones. However, to be relatively conservative, this report has assumed the higher 15% ROE that will have the effect of valuing future projected benefits less than current better-known cashflows. The value attributed to system-wide or synergistic benefits has arbitrarily been set at 5-10% of the total calculated value based on the wholly subjective assumption that as FACTS nodes become more numerous, the value of the power grid information network should follow the performance and value of other networks (e.g. Internet) which increase as the number of contributing nodes squared (see sub-section). Some of the value of the 'system-wide' control versus 'point' control will increasingly be made apparent as critical links and bottlenecks are better managed and overall system reliability and availability are improved with greater utilization of PEs.

Because most of the benefits (as well as some incremental costs) of PEs occur over time, their future values are 'discounted' to present values. In addition, some categories of benefits and costs will likely increase over time differently compared to others. This growth over time or 'inflation' adjustment has been judged to remain different for some of these categories throughout the twenty-year projection timeframe. Although transmission investments and many utility assets arguably have useful lifetimes of 40-50 years, this analysis has used only 20 years to be somewhat more conservative and intrinsically attribute less value to far distant cashflows than present ones. As seen in Table 1 below, it has been judged that issues pertaining to grid security, reliability, and flexibility will become relatively more important than other areas over the next one or two decades, whereas other benefits such as the value of energy will increase in value at what might be a modest 'real' rate of inflation. Implicitly, a modest 'real' rate of inflation would probably be in the historical range of about 2-3%/year so that judged inflation factors which exceed that amount indicate more than just nominal gains but 'real' gains relative to other contributing factors.

Avoided costs	**7%**
Environmental	**3%**
System mgmt benefits	**3%**
Power loops	**3%**
Homeland security	**10%**
Energy saved&power losses	**5%**
Sys flexibility & gen/load uncertainty	**8%**
Tangible & intangible	**3%**
Reliability&sys stability	**7%**
O&M/misc.	**5%**

TABLE 1: Assumed Inflation Growth Factors for Benefits/Costs

Finally, to make this analysis more practical, a hypothetical 100MVAR installation is used as an example. Therefore, on an incremental basis, the initial capital expenditures would be approximately $1.5M for a shunt or series compensation (see Table 3 in the range of $12-20/kvar) whereas for VSC-based reactive compensation it would be approximately $4.5M (in the range of $40-50/kvar depending upon type of product). As the assumptions state, all analyses are done on an incremental basis, so the incremental initial capital expenditure would be approximately $3M. Similarly, as costs and benefits are described subsequently, they are compared on an incremental basis and then finally tallied on a discounted cash flow basis over 20 years as summarized in one example and shown in Figure 1 with an example of the detailed matrix shown in Appendix C.

Benefits: Value of Energy

Incremental power capacity is created when reactive power is injected either actively (e.g. VSC STATCOMs, UPFCs, etc.) or passively (e.g. capacitors and inductors). Typically, active reactive power would 'complement' a larger existing level of passive reactive power compensation which allows it to effectively leverage its capabilities over the entire transmission corridor without actually having to contribute 100% of the total reactive compensation. Although the amount of additional real power capacity which would be available in a given transmission corridor varies according to a wide variety of circumstances, this analysis assumes a base additional capacity of 50% of the MVAR rating and only 1% for incremental real power resulting from the use of VSCs. This incremental benefit is often the result of superior dynamic and transient control in both additional capacity as well as in better managing total power transfer issues thereby often resulting in real power savings by reducing power losses. Consequently, this nominal incremental increase of 1MW when valued at the retail value of energy ($.08/kwh) would be approximately $700k/yr/MW. This amount assumes that the 1MW is used throughout the year for 8,760 hours (@$.08/kwh). Of course, for incremental capacity (or even reduced losses), 100% utilization is not realistic and so an effective loading of 33% has been assumed resulting in a net value of about $230k/year. Depending upon actual loading and performance, this figure could be lower or much higher. Anecdotally, AEP reported that one of their FACTS installations (160 MVAR STATCOM) saved them 24MW in reduced transmission power losses. In the AEP case alone, even assuming that the reduction in power losses were only for 50% base loading situations, the real savings per year could be as high as $8M/year (@retail) which represents over $25k/year/MVAR! In this analysis an amount of this magnitude has not been factored in, but it clearly points out that reduction in power losses and power outages can be financially rewarding. On a national basis, the average cost to a *utility* (and not the final customer, or society in general) is approximately $10k/yr/MW of capacity. Assuming a 50% net effective gain for the utility in either/both reducing power losses and outages yields potential annual savings in the range of $500k/year. On the other hand the greater intrinsic internal power losses of VSC-based devices must also be considered. Assuming a 0.5% greater power loss and using the same effective loading of 33% yields a loss of approximately $100k/year. Consequently, by either of these methods, the net energy gain/(loss) is probably in the range of $150-400k/year.

Benefits: Value of Avoided Costs

When considering building new transmission corridors many factors come into play. In addition to potential regulatory and public roadblocks (many examples abound of delays of 10-15 years), the actual cost of acquiring easements or rights-of-way (ROWs) and finally completing construction can be enormous. For example, recently it is not uncommon for utility easements to cost 3x the actual value of the raw land. In addition, new capital expenditure ranges in the $35-85/kw arena. On a national basis, one approach to ballpark avoided cost is to estimate the incremental carrying capacity achieved with FACTS devices (e.g. 5-10% on average) times the current value of the transmission network ($700B) times a facsimile of carrying costs (e.g. 15%) which yields over $5-10B/year in savings! Additionally, factoring in the cost of regulatory and timeframe uncertainty has often been assumed by academics to increase project cost by 25-50%. Additionally, as was seen in the NGC case in the U.K. which is described in Appendix A, there is ever increasing uncertainty associated with the future load and/or generation growth and their respective new locations since many generators (IPPs) are now locating in non-optimal areas (as far as the grid is concerned). When all of these factors are considered, the total inclusive costs range from $75-200/kw. Note this is a different metric than the oft quoted $1-2M/mile used and is more useful in evaluating $/MW or $/MVAR. Assuming that the avoided costs strategy on average only works for a total of 3-4 years (e.g. (5%to10% extra capacity)/2%/year average national load growth) with incremental carrying costs of 8-10%, and a 10:1 net effective leverage for real power control yields an annual contribution of over $11M/year for the 3-4 years that would be saved. However, from a financial perspective this is somewhat counterbalanced by the 3-4 years which should be added to the total lifetime of the completed new transmission corridor and equipment to keep it apples-to-apples which reduces the effective value of the initial savings by a factor of 2-3x. Provocatively, even this figure of effective savings of $3-5M/year for four years could be enough in some circumstances to justify the entire initial capital expenditure for PE. However to be very conservative, if credit were only given to PE expenditures for the incremental capacity increase and only using a 2:1 leverage factor yields effective savings of approximately $150-300k/year (and again contributing for only 4 years, not 20 as for the other factors).

Benefits: Security & Reliability

The economic value of enhanced grid security and improved reliability is more difficult to estimate but nevertheless very important. It is expected that one of the repercussions of the 8/14/03 Northeast blackout will be a much stronger emphasis by the Homeland Security Department, DOE, FERC, and NERC on these issues. Although the U.S. grid is essentially designed for a N-1 contingency capability, it is instructive to note that large parts of the EU and all of the U.K. are designed with N-2 contingency capability. As with many systems' analyses, diminishing returns are experienced as additional 'layers' of protection or redundancy are added until the system reaches a point where its availability actually decreases with each additional layer because of the extra intrinsic failure rates of any added component or sub-system. Consequently the national grid would be expected to act like many very large systems where the most benefits are gained by adding the first level of protection (N-1), and additional sizable availability results from the second level of protection (N-2), but adding N-3 or more could become economically unviable. Obviously, at the present time, the U.S. for the most part, has decided that even the N-2 protection is not worth the added costs.

However, it should also be pointed out that U.S. power customers are already intrinsically realizing the incremental value associated with the N-1 design of the power grid. As an approximation and a judgment based on similar large system studies (e.g. LLNL, Rasmussen, ADL, etc.), a second layer of redundancy would often result in a system-wide availability improvement in the range of 30-50%. Therefore, if N-2 resulted in a 30% reduction in grid failures (both cost of outages and damaging voltage sags/low power quality, as measured by the impact on the U.S. GDP), this translates into being potentially worth $30-40B/year to society at large. Of course this total amount of value could not be fully subscribed to the ubiquitous utilization of PE devices throughout the grid, however PE would nevertheless play one of the leading roles. Through the use of FACTS devices in the field and the associated system-level simulation and control software which would integrate and optimize grid performance and reliability, the national grid would be much better able to identify both statically and dynamically critical links and bottlenecks and better react to not only N-1 contingencies but in many cases even N-2 contingencies. Assuming a 25% contributing impact and scaling this figure back for both the GDP multiplier and for a utility completing this 100MVAR hypothetical installation results in a value of $50-150k/year.

For clarity, it should be pointed out that the system availability studies discussed above generally assume independent random act of nature so that the probability of having N-2 events is much smaller than the probability of having an N-1 event. However, in the case of terrorist acts against the power grid, the independent random acts have been replaced with coordinated attacks against the most vulnerable links and bottlenecks even to the point of targeting 'correlated' potential failure points (e.g. attack on a combined right-of-way for electricity in transmission and natural gas—which supplies the raw energy for the power generator). These more sophisticated and coordinated attacks require a completely different set of analyses and contingency planning. Presumably these potentialities would fall within the purview of Homeland Security.

Another parallel approach to obtaining a range on the value of reliability would be to consider the 60 major power outages over the last 5 years that each resulted in forced outages to over 500,000 customers and analyze for each outage what, if any, effect having FACTS devices at critical points might have been capable of. For example, if PE devices would have eliminated 25% of these outages with each outage having an average cost of $3-10M, similar values can be ascribed in the $50-150k/year range. Especially key in realizing this value (or even much more than this value!) is the identification of bottlenecks/critical links at interconnections as well as inter/intra utility tie-ins and weak points. The integration of these grid-wide weak points and their identification/correction through the use of a real-time grid simulator or 'manager' will go a long way to help mitigate potential losses. In addition to reducing actual power outages, considerably better power quality should also result.

Loop Power-flows

Although data on a national basis which has recorded the number, magnitude, size, distribution, and loading parameters of loop power-flows is not yet available, insight can still be gained on an anecdotal basis. Loop power-flows occur both within a utility's territory as well as over tie-lines with neighboring utilities. The actual impact of these loop power-flows is quite complicated as the incremental power losses and instabilities they cause are dependent on many interrelated factors including: base loading and impedance, duration, nominal power losses for a particular transmission corridor without the power flow loop, frequency of occurrences, correlation of occurrences with other peaking events, etc. However, a simple analysis can be completed comparing base load power losses (e.g. 2-4% for transmission typically) and the incremental power-flow loop losses that result from incremental I^2R losses. Because the incremental losses increase as the square of the ratio of total power flow (including base load) compared to the base load, they can result in huge incremental losses. For example, on 8/19/99, TVA experienced a loop power-flow of over 8,000 MW on a base load of 2,000 MW. Aside from considerations of voltage stability and sags, the incremental *real* power losses calculates in the range of $80-$150k/hour or potentially $10-20k/hour per 1,000MW. Arguably the largest impact is not incremental power losses but rather the reduced capacity reserve margins and reduced voltage stability margins. For example, TVA was operating at just over PU = .86 which if it had dropped another 1-2% would have resulted in a voltage collapse. That makes a power-flow loop of that size very costly simply from the point of view of running an 'expected value analysis'; in this case, TVA was merely lucky in avoiding a very costly outage. If all of these factors are included, the total all-inclusive losses would be much greater. Assuming these events occur a few times a year on a typical corridor and for just an hour or two per occurrence and applying the techniques used in the discussion on the value of reliability yields a range of $50-150k/year for our hypothetical example.

Benefits: Other Tangible

Power Electronics also have many additional attributes. A variety of tangible but important benefits exist for utilizing the new VSC-based technologies including the additional filtering that is afforded by PEs as well as some improvement in sub-synchronous resonance (SSR) issues, and other dynamic and transient responses. It is now well documented that VSC applications typically require 40-60% less installed area (@substation yard), and some recent installations have even beat these amounts. Assuming that this translates into approximately 5,000 sqft for a hypothetical 100MVAR installation, the value then becomes purely a function of the value of utility real estate (especially measured in today's premium values). As discussed previously in ROWs and easements, this value can be deceivingly high especially for expensive suburban or even urban sub-stations. The value on an incremental basis could be in the range of $10-50k. For purposes of this analysis, a value of $25k was subtracted from the initial capital expenditure amount calculated previously. Other PE attributes include faster response times (by 1-2 cycles) and the innate ability to provide compensation without regard to nominal voltage. In contrast with SVC-based products where compensation drops off linearly, the VSC capability is constant and is intrinsic to its physical design. Interestingly, ABB tried to address this issue by demonstrating that the dynamic response of conventional SVC-based products could be made to match the superior response of VSC-based application by increasing the nominal sizing of the SVC application by 30%! Of course, this solution by itself completely eliminates any real cost differential between the two solutions. Other attributes include the ability of VSC applications to substantially reduce the number of tap changes. For example, it has been documented that tap changes were reduced from approximately 200+ down to 25 which yields potential value of $.5-1/kvar/yr or $5-7/kvar value over the equipment's lifetime. Anecdotally, even TVA in their analysis attributed $1M to reduced failure rates of the mechanically switched tap changing transformer. There is also some value in the reduced 'short circuit duty' and VSC's ability to increase series compensation past the typical 70% limit. The value of all of these other tangible attributes is approximately in the range $50-100k/year and potentially 5-10x that figure if ABB's demonstration figure holds true (ie 30% size up-rating for SVC for equivalence to VSC which works out to be $10-15/kvar added VSC benefit).

Finally on the negative side, VSC products do exhibit higher intrinsic power losses (by .5-.75%) where the scale compared to IGCT is approximately 2.5x for IGBT and in the range of 4-5x for GTOs. In addition, there are probably higher O&M costs currently for SVC compared to passive compensation techniques. However, it is expected that as the number of components is substantially reduced (see later discussions) and the associated reliability improves as a result, the O&M costs will also drop. For purposes of this hypothetical example, incremental O&M has been assumed to require an additional 3% of initial capital expenditures over and above utility average figures for O&M departmental expenditures that translates into approximately $90k/year of extra expenses.

Benefits: Environmental

Environmental benefits are similarly difficult to financially quantify although important trends have been developing over the last several years. Aside from achieving 'positive public image' with regulators and the public at large, it is still difficult for utilities to directly benefit from a reduction in greenhouse gases such as CO_2, NOx, etc. However, some generators have begun to hit their annual ceiling of allowed pollutants discharged. Similarly, although the U.S. is not a signatory of the Kyoto Protocol, the EU and other industrialized regions are setting up frameworks for providing a financial marketplace for CO_2 pollution credits. Providing such pollution credits have been tested in the U.S. for different purposes but are still instructive. These credits are non-trivial, for example @ $.4/ton credit, it could be worth over $400k/yr in our hypothetical example. There is similar potential for other pollutants and wastes as well. For purposes of this report, an expected value or probability of 20% has been applied to yield a contribution in the range of $50-100k/year. Over the long term, the management and potential reduction of greenhouse gases will almost surely be negotiated to be an additional financial incentive as well and will likely be valued at even higher expected values.

System Flexibility and Generation Location Adaptability
Over time, the flexibility associated with the utilization of VSC-based products will greatly expand. For instance the 200 MVAR Convertible Static Compensator (CSC) at the NYPA's Marcy substation is a portent of things to come. The NYPA CSC has the ability to be reconfigured to handle 11 different modes of operation. This multi-functionality allows for dynamic reconfiguration to meet many changing conditions ranging from reactive compensation to unified power flow to back-to-back tie-lines. Having this level of multi-functionality also allows utilities to better meet the ever increasing uncertainty associated with load and generation locations. Consequently such uncertainties as where a given IPP will be locating their next generation facilities or windfarm sources as well as distributed generation issues can all be handled more productively. Several relevant examples of the need for generation flexibility are found with NGC in the U.K. (see Appendix A) where over the course of ten years, over 20,000MW of generation were retired and another 25,000 MW of new generation were often located in completely different locales. Similarly, New England has seen over 10,000 MW of new generation being built in just the last 5 years. Because real field experience is essentially lacking at this moment, this level of performance is subjectively assumed to add about a 5% overlay of expected value especially in the long term as utilities learn how to more fully utilize the multiple capabilities of their FACTS systems. As distributed generation (DG), energy storage (SMES), renewable energy (windfarm), and other alternative sources are added to the power grid, additional benefits of PE's flexibility and performance will be realized.

Benefits: System-wide & Synergistic
There is considerable unrecognized value associated with being on a managed network where the synergistic value of 'system-level' benefits can be realized that will exceed the benefits associated with simple 'point' control and management. Moreover, the 'self healing grid' also has the intrinsic benefit of being able to take advantage of and optimize over the entire system thus exhibiting 'system-level' control and not just 'point' control, thereby helping to realize another layer of value 'hidden' or tied-up in 'integration' which had been previously lost and unleashing it thereby benefiting all participants. As with the Internet and other large networks, the real value of a network and its potential increases as the square of the number of contributing nodes (N^2) and further increases as the number of points that can simultaneously communicate and interact with each other grows. As the proliferation of FACTS devices increases, the synergistic and integrative

benefits will begin to become more apparent as innovative system-wide algorithms and strategies are implemented, tested, and improved upon.

In a sense the U.S. electric grid system is just beginning to move into this far greater stage of ***network*** information and management as it grows from a very small number of relatively isolated FACTS devices and develops into a large number of interconnected FACTS devices over regional and national ties that will allow the grid to truly optimize, transport, re-allocate flows, compensate, project and correct bottlenecks, and otherwise perform the 'self-healing' of which it is capable. The future value of the grid 'network' (no longer just 'system') will be further amplified when it is coupled with advanced forward-looking capable real-time simulation capability (e.g. using supercomputers analogously to the complex national and global weather projections which are simulated. When these real-time fast simulations and modeling have the ability to look seconds or even several minutes into the future, the value to both reliability and grid security will be increased many-fold. These concepts are heavily connected to EPRI's concept of the 'self healing grid' which requires ubiquitous PE devices, sensors, monitoring, and a variety of other management and control devices throughout the power grid. Commensurately, the relative value of energy saved, system flexibility, system management, and avoided cost will similarly increase. These system-level or synergistic benefits won't fully be valued until more of the grid 'network' is in place, nevertheless, its value has been conservatively assumed to be worth an additional 5-10%.

Total Benefits

When all of these benefits (and some incremental costs) are accumulated, adjusted over 5-20 years into the future, and then discounted at the implicit 15% return on equity (ROE) rate assumed for the utility industry, yields the bar graphs shown in Figure 1 below. Note that the sum of all of these discounted present values (NPV) is shown at 1/10 of its actual amount as to not distort the Y-axis so the actual total NPV is almost \$8M. It is important to bear in mind that this figure is the 'excess' value of the investment to society *after* the investing transmission entity owner has earned a return on equity of 15%! This excess essentially represents additional 'societal value' which is then available to be 'split' amongst the appropriate parties. Naturally, some of this 'societal value' is effectively passed on to customers in the form of the value of more reliable, stable, and available power while other contributions could be directly passed on to customers in the form of provisional discounts when/if the savings are realized. What this really means is that regulators have considerable latitude in providing customers or society in general a negotiated portion of the 'total value pie.'

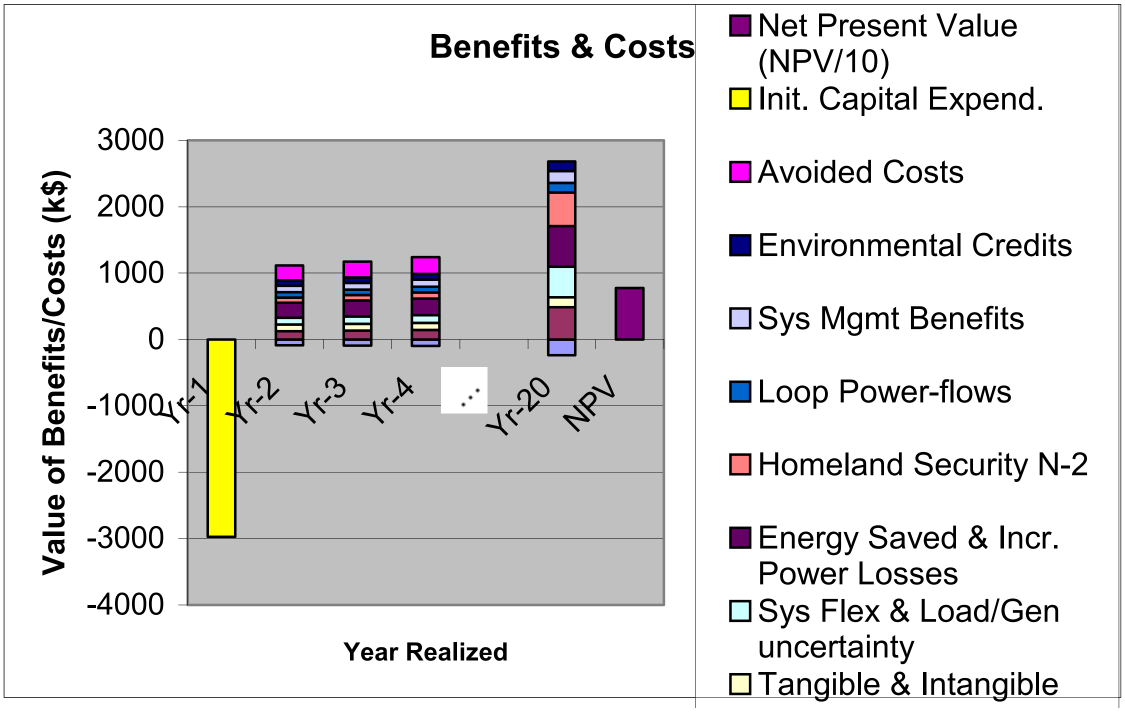

FIGURE 1: Example of Discounted Cash Flow Value of 100MVAR Investment

Clearly, as Figure 1 illustrates, society and all the other participants in the grid (e.g. utilities, vendors, customers, etc.) would greatly benefit from appropriate grid investments, but there are no market incentive mechanisms to appropriately allocate both the costs and the benefits of such reasonable investments.

THE CURRENT SITUATION: The "Problem of the Commons"

As the economic analysis progressed for this study, it became clear that some key market drivers or mechanisms were not fully operational with respect to Power Electronics and its potential role in the national power grid. Most notably, the market mechanisms for normal returns on capital investment and associated risk and management of grid transmission capacity/reserve margins has steadily degraded over the last decade creating a classic "Problem of the Commons" wherein no one participant is incentivized to make what would normally be entirely appropriate investments in the grid because there are no effective overall rules and standards for recouping those investments. This "Problem of the Commons" is one of the most important recurring themes throughout the decision-making for transmission grid investments; it is worth addressing the general issue in more detail so that regulators and other planners can be better informed. This is especially important given the analysis described above where both utilities and 'society' can realize substantial economic benefits by installing PE within the transmission grid, but the "Problem of the Commons" interferes and distorts the incentives that should be in place to provide an adequate level of infrastructure investment.

This "Problem of the Commons" was first identified as a class of economic issues from experience associated with the public grazing rights for the Boston Commons. There any citizen was allowed unlimited grazing rights on the public parkland known as the Commons. When Boston was small this arrangement worked equitably as there was sufficient capacity to accommodate everybody's animals. However over time, as the town grew, all citizens had a strong incentive to graze their animals as much for free as possible before resorting to other grazing resources (e.g. using their own private lands, if that was available). Of course what happened over time was that the Commons land was vastly overgrazed and was made virtually 'uneconomical' to use by anyone. This phenomenon whether it is applied to grazing rights, water rights, air or water pollution, highway usage, and others shows up repeatedly in different forms. Consequently, in the end, any 'Commons Problem' suffers and steadily degrades and society pays the price (by losing or degrading a resource that would have resulted in some ongoing value had it been managed better). Instead in the case Transmission Grid Assets, the 'Commons' problem incentivizes the users (i.e. utilities) to spend investment funding at the minimum amount possible where the incentive is to 'avoid the wrath' of the local public and their state PUC (as well as federal regulators such as FERC). Because necessary and sufficient market mechanisms have not been in place for over a decade (and even with the post-NE blackout repercussions it will still take considerable time to correct), the normal investment decision-making process of weighing financial and regulatory tradeoff risks and returns has been terribly skewed. Consequently, the early-stage risk profile for product development and market penetration and acceptance have been effectively shifted out to longer timeframes and shifted up to requiring higher investments – in other words, independent commercialization won't happen on an accelerated basis until the development process has been taken further along than it would normally require. This is further illustrated in Figure 4 in the next sub-section.

A simple example of these "Problems of the Commons" issues are illustrated in their Transmission Grid equivalent as outlined in Figure 2 below:

- Example: Value of increasing capacity on a transmission corridor by 1MW for a year could be as high as \$700k/yr (retail @\$.08/kwh)
- Societal value could be as high as \$20-30M/yr! (with the GDP multiplier)
- However, Transmission's piece is likely only \$70k/yr
- Worse yet, from wholesale perspective, perhaps it is only \$20-40k/year
- Worse still, Transmission 'passes' losses through, so it may really cost =\$0
- No market mechanism to 'allocate' benefits & costs to appropriate participants
- Will not make marginal investment decisions except in extreme case of 'avoiding wrath'
- Bottom Line: 'societal value' says "yes", actual utility incentives say "no"

FIGURE 2: Example "Problem of the Commons" in Transmission Grids

In the hypothetical example of Figure 2, the decision making that a utility might go through in evaluating adding an incremental 1MW of capacity on a transmission corridor is made through the skewed process outlined. On a retail basis, the annual revenues (to somebody) would be worth \$500k to \$1M/year (@\$.06-\$.12/kwh). Then depending upon how much of the 'total pie' is allocated to the transmission entity (say 10%), 'transmission's piece might be worth only \$50-100k/year on a retail basis and only 30-50% of that on a wholesale basis. Worse still, most transmission entities directly pass through 'losses' and inefficiencies, so in a bizarre twisted way, they would have no financial incentive to improve their grid system whether it be for extra capacity, Var compensation, system management and reaction, reliability, etc. Instead, the driving incentive the transmission entity has is to 'avoid the wrath' of the local public utility commission by staying out of the newspapers. The transmission owners would be incentivized to only spend the minimum 'barebones' amount required to keep the system going.

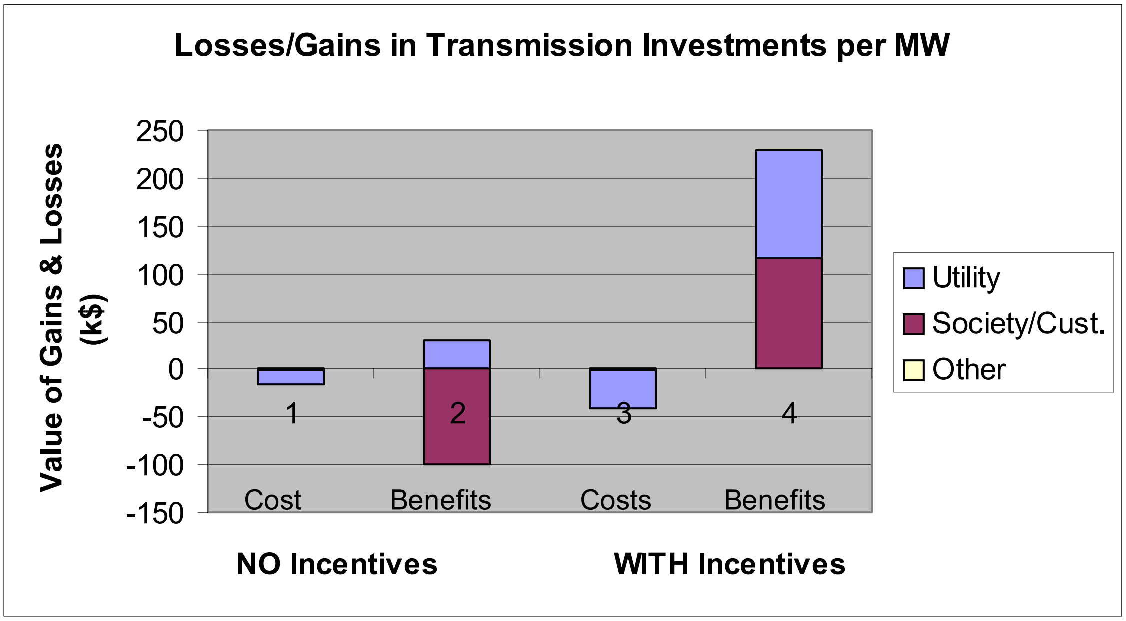

FIGURE 3: "Problem of Commons" Applied to Transmission

As is illustrated by Figure 3 above, the two conditions of (1) the "Commons Problem" with no market incentives and (2) more representative market incentives for risk/return decision-making are described. With NO Incentives, the transmission grid owner is incentivized to spend the minimum amount necessary (here $15k/mvar) through 'conventional' Var compensation investments. As a result, the utility realizes a minimal return (if any) and society at large loses a considerable 'opportunity cost' represented by the ($100k) loss. These estimates are a simplified version of the analysis completed previously for Business Case 1. In contrast, WITH Incentives allows the transmission owner to spend additional money (e.g.$40k/mvar) but realize more than $200k of total future value (which has been arbitrarily divided 50/50 between the transmission owner and the customer). The actual split (e.g. 50/50) is less important than the reality that some allocation process has been negotiated which allows grid owners/operators to make rational investment decisions.

Although our transmission investment incentive market is dysfunctional, it is not completely broken and can be put back on track relatively quickly. A real example of this kind of transformation is described in Appendix A. Here the U.K.'s NGC faced a similar deterioration of their power grid in the early 1990s after deregulation with few incentives for appropriate future investment. After a shared profit/loss incentive was negotiated with their regulator, NGC increased investments by over 300% and over the next several years saw dramatic improvements in both system performance (e.g. availability, fewer outages, etc.) and reductions in actual operating costs. Although this example is, of course, not an exact analogy to the U.S. with our many-leveled and varied regulatory jurisdictions, it is still highly instructive and can probably shed some insights into potential U.S. solutions.

TRANSMISSION VALUE PROPOSITION

As both Figure 1 has illustrated and the previous discussion on the "Problem of the Commons" highlights, there exists ample 'societal value' for these PE investments, but inadequate incentives exist to encourage those investments to actually occur. In addition to a reasonable return being earned by the transmission entity owner, there exists considerable 'societal value' which could be divided amongst the various constituencies through negotiations with regulators and other parties. Each party can play a role or multiple roles as indicated below in the transmission value chain:

- Power Generators (can be given incentives to inject VARs at the power source which is in general 2-3x more efficient or less costly than at distant locations)
- Transmission infrastructure owners (can play multiple roles, but primarily to insure a reliable, more available, lower power outage, and higher power quality network for which they will make investments and receive a reasonable return)
- "Retail Wheeling" and "Energy Contracts" (these players will be penalized for longer distance transports where additional VARs are required and incentivized to arbitrage energy costs across as wide a network as possible for efficient production and consumption)
- End Customers (Residential, C&I players will all receive higher power quality and will be able to realize savings through the negotiated incentives put in place by regulators)
- Society (in general will benefit because a larger 'value pie' was created to be sliced up and through the GDP multiplier will likely return 20-40x the actual contributed value)
- Equipment Vendors (will finally begin to realize the $5-10B marketplace that would then be available in Power Electronics)
- Regulatory (FERC, NERC, PUCs, etc. play their respective roles as intermediary between society and those entities which physically manage and operate the national grid)
- Legislative (Congress and states play their roles to enact laws that further encourage accelerated investment in the transmission network through Investment Tax Credits, ITCs, accelerated depreciation mechanisms, and other investment incentives)
- Homeland Security and DOE/ECs (play their respective roles as sponsors and supporters and potentially even funders for some grid improvements which are most critical)

In the end, how these benefits are allocated must be negotiated effectively amongst all of these parties, but it is nevertheless clear that substantial and real value exist to society for implementing and accelerating these improvements. One can only hope that we do not have to wait for another Northeast blackout or a terrorist attack on the grid to finally catalyze appropriate action.

IS THERE STILL A ROLE FOR CEIDS?

Under normal market mechanisms, CEIDS's and E2I's continued seeding and participation in further PE efforts probably would not now have been required especially in the areas of additional pilot and field demonstrations. Perhaps also underlying this issue is the more general question "Is the PE industry and its primary vendors at a point in their product development cycle where commercialization is now feasible and CEIDS/E2I are not required to continue funding 'risk' or 'early stage high risk' endeavors. Most notably, the market mechanisms for normal returns on capital investment and management of grid transmission risks/reserve margins has steadily degraded over the last decade creating a classic "Problem of the Commons" wherein no one is incentivized to make entirely appropriate investments in the grid because there are no effective overall guidelines and standards for recouping those investments and allocating both costs and benefits. Consequently, the 'Commons' suffers and steadily degrades (in this case, the transmission grid network), and in the end, society pays the price (with a less reliable and secure grid as well as more expensive energy). As described previously, the 'Commons' problem instead incentivizes spending investment funding at the minimum amount possible to 'avoid the wrath' of the local public and the state PUC (and certainly federal regulators such as FERC). Because these market mechanisms have not been in place for so long (and even with the post-NE blackout repercussions it will still take considerable time to correct), the normal early-stage risk profile of product development has been effectively shifted out to longer timeframes and shifted up to requiring higher investments – in other words, independent commercialization won't happen on an accelerated basis until the product development process has been taken further along than it would normally require. These notions are illustrated in Figure 4 below.

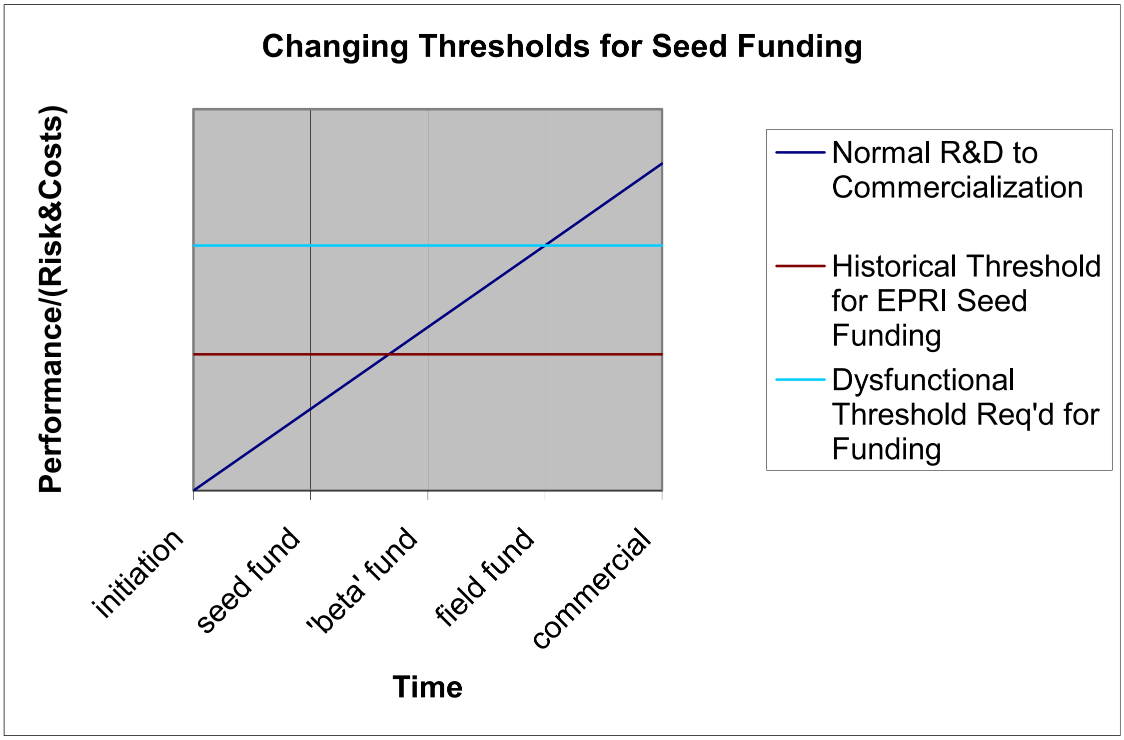

FIGURE 4: Increased Risk/Return Threshold for Self-Sustaining Product Development

As can be seen in Figure 4, the ‘normal’ or typical level at which the risk/return tradeoff for a commercially viable self-sustaining product development cycle has shifted to a higher level; or in other words, higher outside levels of funding are now required before viable self-sustaining development cycles could be supported when financial risks and returns are weighed. In this key respect, CEIDS’s and E2I’s continued strong participation is paramount. Not only are there a number of technical efforts to push, but CEIDS and E2I can lend a tremendous hand in coordinating utilities, regulators, and vendors in several of the following important ways:

- Encourage standardization of PE equipment
- Education of both utility planners/designers and regulators on technical and economic benefits of PE applications
- Encourage forming a buying consortium for PE equipment to help accelerate cost reductions and volume foundations
- Gather and dissemination of PE field and operating experience

Because of the highly dysfunctional transmission investment incentive structure that currently exists, CEIDS/E2I’s efforts are still required, perhaps more than ever, in these areas for at least several more years and their efforts will help to dramatically accelerate PE utilization in the grid infrastructure.

WHERE SHOULD R&D EFFORTS BE FOCUSED?

As a result of numerous discussions and analysis of the limited field data available from several FACTS sites, two important areas are clearly in need of continuing funding and effort: (1) the improvement in PE equipment reliability and availability, and (2) cost reductions of PE equipment. As illustrated in Figure 4 above, PE investment justification for use in the transmission power grid is highly dysfunctional at this time and will require continued risk funding by CEIDS and E2I.

For example, reliability as a general issue has both economic and a very large perceptual value (to prospective utility customers), especially if VSCs are misperceived as being unreliable. Whether this perception is accurate or not, is less important than the actual perception if the net effect is to halt further field installations which reduces market acceptance. Similarly, a more generalized analysis of Power Electronic costs, their trends, and future cost levels is considered both highly desirable and achievable. Given the problem of the 'Commons' that is faced with transmission PE investments where virtually none of the many additional performance attributes, system-wide synergistic benefits, and their associated economic values of the VSC-based products were being considered, it is especially important for CEIDS/E2I to continue their support in these arenas. As a consequence of these issues, the remainder of this sub-section focuses in greater detail on the following two opportunities:

- The Value of Reliability in Power Electronics
- Generalized Cost Issues for Power Electronics

It is believed that these two areas possess considerable short-term returns and their success would greatly accelerate further market penetration which would then allow the many additional 'layered' benefits of PE equipment to be realized (e.g. system-wide, management, reliability, dynamic stability, and synergistic).

BUSINESS CASE 2:
Value of Reliability

Of course new or emerging technologies and applications will always have their challenges as they try to gain a market foothold. The current shortcomings of the initial pre-production tested VSC-based technologies are in the two areas of reliability/availability and product costs. Some preliminary reliability information has been obtained from two VSC sites (AEP's UPFC and TVA's STATCOM). These data are contrasted with similar data for SVC applications and HVDC applications (to establish a market acceptable threshold). Although this information is preliminary and somewhat outdated at this time (pre-1994 for SVC and pre-2000 for VSC), the results are still illustrative and are summarized in Table 2 attached. As can be seen in Table 2, the VSC-based applications had forced outages in the range of 17-27/year compared to SVC-based forced outages on only 5-9/year or approximately 200-300% more forced outages.

	Forced Outages/Year
HVDC	9
SVC	5-8.5 (based on trend)
STATCOM (@TVA)	17
UPFC (@AEP)	27

TABLE 2: Example Availability Data (Forced Outage Rates)

This information is based on preliminary unpublished data and represents information that is several years out of date and is therefore subject to review and analysis of more recent data (especially with respect to SVC data which was pre-1994). It should be noted that more recent data has just been made available to CEIDS at the October 20-22, Utica, NY, FACTS Conference including information from Vermont Electric Power for 2.5 years of operating experience with their Essex STATCOMs which resulted in an average availability of 95.04% (but also showing tremendous promise by demonstrating availabilities of over 99.9% for two periods of six months). Similarly, AEP with their most recent data supported a current reliability number of 96%.

It is important to bear in mind that reliability and availability are two different facets of the same story and neither metric captures the 'whole' story. Availability is often measured in terms of what percentage of the year is a given piece of equipment 'available' for usage; thus 99% availability still implies a total of 88 hours that the equipment was down. In contrast, reliability is the instantaneous probability that the equipment will fail under a particular set of conditions (e.g. operating conditions, stresses, etc.). Often these probabilities are strong functions of the specific operating conditions (e.g. lower reliabilities under design loads or other stresses). Given these differences, it is difficult to say what the availability of these units was without knowing the mean time to repair (or at least estimating it). Unfortunately, actual cost of repair, time to repair, and lost energy or resulting grid difficulties were not available, so for purposes of this cursory analysis, it was assumed that each forced outage required 1-2 working shifts of a truck and crew (including a 300% overhead rate) and that it would take 24 hours from failure to repair to get the equipment back on line. Some of the recently released data indicate that the mean time to repair (MTTR) is closer to 2-3 days. Additionally, it was assumed that the cost of the equipment used in the repair was approximately the same as the cost of the labor and that 10% of the forced outages would result in some impact to customers and some lost energy delivery (@$.08/kwh). With these assumptions, Figure 5 describes an illustration of what this incremental 'un-availability' might represent in economic terms. Figure 5 indicates that the incremental 'un-availability' of the VSC application may cost in the range of $200-450k/year/site. This is especially important to achieve high availability 'when it is needed!' Additionally, if SVC sites were assumed to represent an availability of approximately 98% (which was a figure many have used), this would imply then that the two VSC sites have a corresponding availability in the 94-96% range (assuming equal times to repair). Another interesting way to interpret this information is to state that an improvement of 1% in availability (when you need it) saves approximately $50-100k/year/site. This is a substantial number and should be refined. A CEIDS/E2I objective of 99% availability for PE is achievable and will have tremendous impact.

In defense of the reliability of these two VSC sites, it must be pointed out that they were 'beta' field sites and very much pre-production so one would expect to experience considerably more 'infant' and early stage failures as the technology and its applications 'rides down' the typical reliability 'bathtub' curve toward product maturity. Additionally, it is also important to understand that these data and Figure 5 make no attempt to 'normalize' the availability data for a fairer 'apples-to-apples' comparison where equivalent functionality and complexity have been taken into account. Nevertheless, many utilities have forgotten that these VSC units were 'first out of the box' beta units and not production units. Unfortunately, for many utilities 'perception is reality' and VSCs have perhaps unjustly earned the reputation of being more unreliable than SVCs. At a minimum, it would be helpful for CEIDS and E2I to re-educate its utility membership (and perhaps others as well, such as regulators) with more recently gathered reliability information and data which has been normalized for the same functionality and operating conditions.

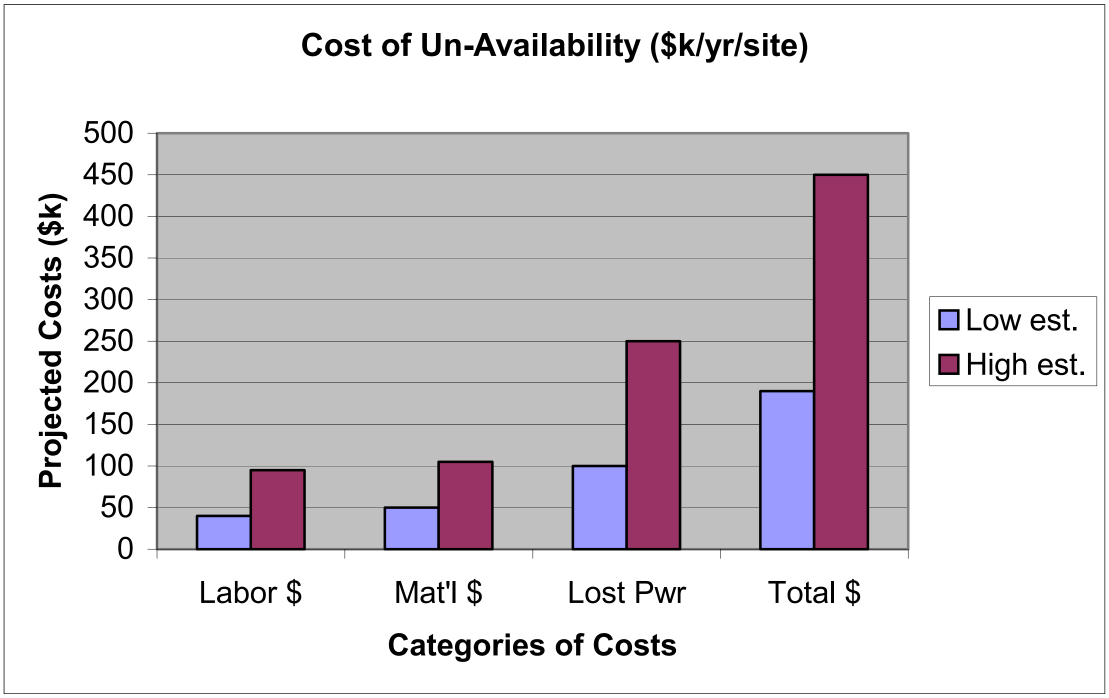

FIGURE 5: Cost of Un-Availability

Most of the reliability and availability issues can be greatly improved by more thorough testing and choice of sub-components (e.g. cooling system, controls, power supplies, other auxiliary sub-systems, etc.) while some aspects may be more fundamental to better testing and design (e.g. magnetic flux saturation effects resulting from unusual current surges). The basic reliability of the actual silicon devices (GTOs and IGBTs) is very robust. It is also interesting to note that in discussions with PE vendors, it was repeatedly mentioned that even though utility trials of VSC applications were ‘pilots’, that the utilities still perceived them to be directly comparable to much more mature reliability rates of SVC-based applications which is not realistic. The actual direct failure rates of the PE components themselves are almost negligible and almost all failures are found in the auxiliary, control sub-systems (e.g. gate drive and firing), and cooling sub-systems.

Given the strong negative perception associated with PE reliability, it would probably be warranted to perform extensive field analysis and failure information and to better educate utility users on the actual reliability/availability data and what that data imply. The compilation of actual failure data as a function of time/stress/mode/component and its comparison to theoretical availability analyses comparing VSC to SVC(conventional) and actual tested MTBF and MTTR numbers for each major component and sub-system would be indispensable in helping to accelerate this technology’s acceptance and market penetration.

This analysis indicates the ‘value’ of equal or better reliability leading to enhanced availability ‘when you need it’ (compared to SVC) is worth $250-450k/year which has a NPV of between $2-4M over a twenty year period. In an economic sense, this is equivalent to decreasing the initial capital expenditure by $3-5/kvar or approximately 7-12%. In concert with the next sub-section's discussion on cost reduction, the marketplace for PE equipment will see a large acceleration in volume and acceptance and could achieve rates of 10-20 installations per year after a stabilization and 'acceptance' period of a couple years.

BUSINESS CASE 3:
Generalized Case for Cost Reductions in Power Electronics

The other major shortfall of VSC-based applications, namely, product costs, is worth addressing independently. Almost without fail, early production units (in any industry) that utilize new technologies experience higher initial costs that then steadily decrease over time as cumulative volume and manufacturing experience accumulate. However, it is expected that as power semiconductors continue to experience ever decreasing cost economies, and some volume production can be achieved, that costs would similarly improve and would place VSC applications in the position of being very competitive. Interestingly, more than one vendor told me that if there were an equivalent number of VSC unit purchase compared to SVC, it would likely cost a similar amount. Of course, this is a classic 'chicken or egg' quandary. However, it nevertheless indicates that VSC applications can compete with SVC while still providing many other superior attributes and functionality. There has also been steady improvement in PE controls and approaches that will additionally enhance both reliability and cost reductions as the component costs are reduced. For example, recent laboratory-based work with Emitter Turn-Off (ETO) and Super GTO components hold considerable promise for dramatic reductions (30-40%) in component count and costs as well as commensurate improvement in reliability. These potential 'breakthrough' technologies are natural projects for CEIDS's involvement, but should not be its sole focus as the there is still considerable trailblazing to do with the existing VSC applications.

Some background information, such as generalized cost of equipment, is relevant to all of the business cases and their analyses and is presented in this sub-section. Although estimates varied widely for both costs and potential economic value (especially with respect to synergistic, broader grid control and management, and other intangible benefits), the following table is the result of numerous discussions with both vendors and actual utility customers. It is important to point out that the value represented in this table are approximate, and the overall conclusions associated with one given business case are not solely determined by the costs shown here, but rather the 'mosaic' of overall benefits and costs. The following Table 3 of costs is approximate and varies with the age of a given VSC installation (e.g. earlier pilots):

Basic Costs Estimates (assuming +/- for VSCs)**:**

STATCOM	$40/kVAR
SVC	$35/kVAR
UPFC	$40/kVAR
TCSC	$50/kVAR
PSS	$70k per #of units
Shunt Compen.	$10-13/kVAR (mech. Switched)
Series Compen.	$15-20/kVAR

TABLE 3: Basic Cost Comparisons

The relative contribution of various subassemblies and components that make up VSC applications versus conventional SVC applications is shown in Figure 6.

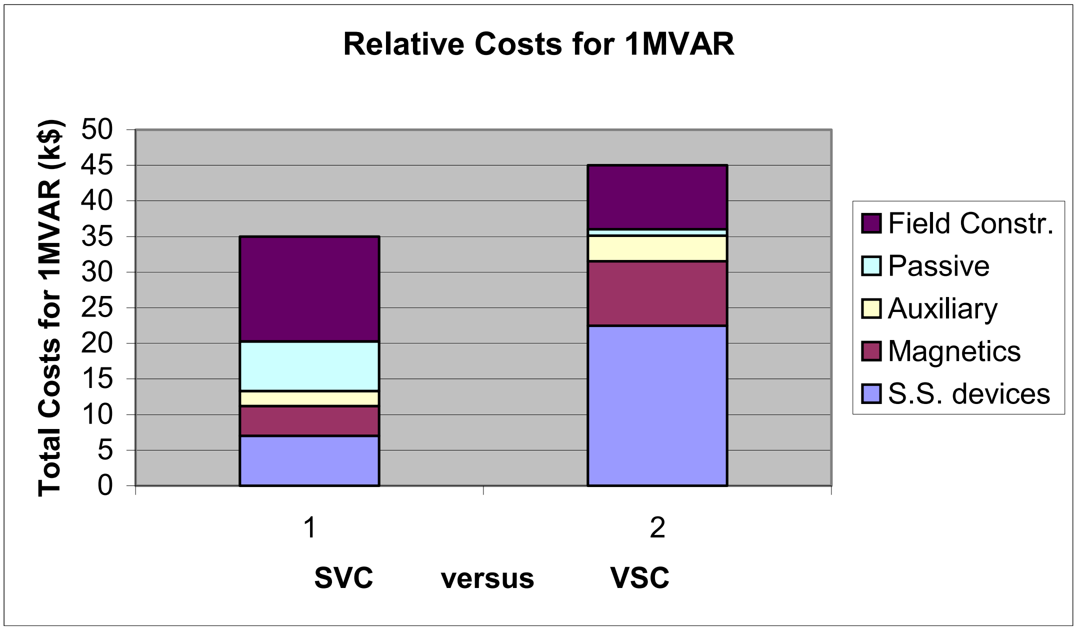

FIGURE 6: Relative Contribution of Costs to Power Electronic Applications

From Figure 6 it is apparent where cost opportunities lay for improvement. Thyristor-based SVC applications are relatively mature (20+ years) and the contribution of the physical thyristors will not likely be reduced in the future. On the other hand, for VSC applications the actual integrated circuit device component cost comprises half of the total cost and as cumulative volume and production experience accumulate, substantial reductions should result. Under normal circumstances, these devices would be expected to decrease in price by 3-5%/year so that over the next 5-10 years, a total reduction in manufacturing price of between 10-20% should result. The second apparent opportunity resides in reducing or eliminating the contribution of magnetics to overall product cost. It is this exact point that pushes alternative design approaches as well as offering promise for such solid state alternatives as ETOs and other newer technologies.

Informatively, half of the vendors stated that, in general, the cost differential between SVC applications and VSC applications was approximately 20-30% while the others indicated the differential was probably larger than 30%. All vendors agreed that at current order rates (e.g. a couple VSC applications per year at most!), it was very difficult to justify their spending much for further research and development. Informatively, some vendors even stated that at equivalent volumes, VSC applications would be similarly priced to conventional thyristor SVC applications. It was also generally recognized that for small VSC installations (e.g. distribution STATCOMs), that the cost per delivered KVAR was considerably higher than for larger MVAR sites primarily driven by custom engineering costs (which could easily represent 50% of the total costs and which implies some opportunities for other CEIDS efforts). It was also interesting to note that one vendor (ABB) demonstrated that the faster response of VSC devices could be met by increasing the SVC 'rating' by 30%. For example, the superior dynamic response of a 100MVAR VSC installation could be matched by installing 130MVAR SVC equipment. Interestingly, this 30% up-sizing equipment need essentially matches the cost differential that would have existed so that equivalent performance (as measured by response time only) can be obtained at the same cost level. This comparison amply points out some of the under-appreciated attributes of the more capable VSC-based applications even within an apples-to-apples view.

In concert with the previous sub-section's discussion on reliability improvement, the marketplace for PE equipment would see a large acceleration in volume and acceptance and could achieve rates of 10-20 installations per year after a stabilization and 'acceptance' period of a couple years. This also agrees with the total marketplace calculation performed earlier of $100-200M/year for PE equipment to support leveraged reactive compensation requirements for a 2%/year average U.S. load growth. In addition, the total PE marketplace (including retrofit requirements) would be in excess of $5B which would represent another $100-200M/year of demand (depending upon build-out). Consequently, the successful completion of the VSC reliability and cost reduction programs would likely help accelerate volumes from the 1-2 sites/year current rate to possibly ten times that rate. In addition, if over the next couple of years, the "Problem of the Commons" is resolved to re-encourage marketplace incentives for transmission system investments, the total marketplace for PE equipment would increase by an additional factor of 2-3x. As Appendix A describes, these volume increases were indeed the result of transmission investment incentives put in place in the U.K. with NGC which increased its investments by over 300%/year over previous rates.

OTHER RECOMMENDATIONS

In addition to the generalized case for transmission system investment presented earlier, several other observations and recommendations are worth mentioning. These additional recommendations are important because each will help accelerate the overall growth and market penetration of VSC-based PE products. These recommendations are not necessarily appropriate for CEIDS or E2I to directly assume, but could be accomplished by groups of utilities or user groups (similar to the one that was formed after the D.C. Power Conference in June, 2003. These additional recommendations are as follows:

- Encourage standardization of basic sizes of PE equipment (e.g. STATCOMs 'modules' rated at 50 MVAr and 245kV and 100 MVAr and 500kV, etc.) so that manufacturers have less custom engineering and less custom manufacturing to perform for each utility bid.
- If possible, encourage a utility buying 'consortium' which as a group agrees to buy a minimum number of different PE modules over some period of time (e.g. 3-5 years), again to encourage vendors to standardize and provide them with a clear 'carrot' to win, realize some real volume, be as competitive as possible, and possibly kick start other 'ripple' effects from other utilities outside of the group. Perhaps, the 'carrot' for utilities would be the ability to realize a real and substantial 'group discount' by pooling their orders.
- The education of both regulators as well as utility planners on the real technical and economic benefits of the many other attributes of PE applications cannot be understated. Even vendors did not try to quantify any of the other benefits because their prospective customers (the utilities) were so focused on only minimizing costs and avoiding the wrath and negative attention of their local PUC and public (e.g. in the event of a blackout). Again, this is the 'problem of the Commons' and until all of the benefits are understood and quantified (even if only subjectively), the best optimized decisions for grid investments and timing will not be made. Investigate and fund education and training oriented efforts for utilities to include the at least the following areas: (1) assist utility planners/analysts with understanding other economic benefits of PE, (2) perform analyses for given situations on actual distribution of other economic benefits for transmission loss savings, loop flows, better voltage stability, and (3) training and seminars for federal regulatory, state PUC, and energy commission personnel to educate them on why 'cheapest is not always best.'
- Gather, analyze, and disseminate field experience from the dozen U.S. FACTS sites and try to access similar data from the dozen other sites around the world (perhaps through confidentiality and information sharing agreements). It has been clear that for better or worse, many utilities have not been interested in even considering FACTS approaches because of the paucity of statistical operational, reliability, availability, and maintainability information. Bottom line, if there are problems, identify them and fix them! Many utilities and their local regulators

will not even consider products that do not have some minimum amount of field experience information upon which to evaluate them.

- As a result of this summer's Northeast power blackout, some potential follow-up efforts for CEIDS/E2I might include:
    - Educate regulatory/energy commission staff on added benefits of PE,
    - Make argument that for a $50B energy package to update transmission, upgrading to PE applications would constitute less than 5% of that,
    - Value of 'system' vs 'point' control and management issues and benefits,
    - Should include software modeling and simulation for reduction in custom engineering requirements,
    - Selective determination of either most critical or vulnerable grid points or those points that would yield the most payback for PE investment
    - Modify and augment existing CEIDS effort for 'engine' simulation model to be applied to entire US grid to capture actual nationwide and regional realities
    - Did FACTS installation play any roles (+ or -) in blackout? How could it have helped?
    - In what critical ways does FACTS provide for additional near real-time control and/or management during a power crisis?

CONCLUSIONS

The accelerated utilization of Power Electronics (voltage sourced converters, VSCs) within the U.S. transmission grid network has been severely stalled for two primary reasons: the "Problem of the Commons" (i.e. lack of appropriate incentives for investment) and a general misperception by the utility industry of not valuing the many synergistic and system-level benefits which can be attributable to the use of PEs within the transmission grid. As with the Internet and other network systems, the real power or value is proportional to the square of the number of contributing nodes (N^2) and as FACTS devices become more prevalent, many of the heretofore unappreciated benefits of 'system-wide' and synergistic attributes of PE will stand out.

The lack of transmission investment incentives for the past decade and half can be characterized as being similar to the "Problem of the Commons" experienced centuries ago in Boston where nobody had an incentive to preserve and manage the valuable 'public' resource of grazing on the park-like Commons. Without proper incentive systems in place, the U.S. transmission system will continue to deteriorate and will exhibit an ever increasing number of failure modes (e.g. outages, reduced power quality, instability, sagging voltage, etc.). This problem is further compounded by the unfortunate perception of PE equipment being 'un-reliable' and too costly. Improving the reliability of both equipment and transmission corridors have tangible and quantifiable benefits. Although it is sometimes difficult to assess all of the benefits (and costs) of Power Electronics in transmission applications, the cumulative value of energy saved, VARs produced, avoided cost, value of reliability and increased availability, environmental benefits, reduction in loop power-flows, other tangible and intangible benefits, and the least appreciated system-wide and synergistic benefits can be generalized to be worth in the range of two to five times the initial expenditure (on a discounted cash flow basis using 15% as the implicit discount rate or 'return on equity' on transmission investments). For example, for a 100 MVAR VSC hypothetical installation, and incremental initial capital expenditures of approximately $3M, the net present value (NPV) is still over $7M. Since the transmission entity owner has already 'earned' a 15% return, this still provides over $7M of additional 'societal value' which can be 'split' or negotiated amongst other participants (e.g. customers). It is expected that in the future, the growing value that these benefits will contribute in addition to the huge synergistic benefits possible through 'system-wide' point control versus today's 'point' control will increase these financial multiples even more.

This business case analysis of investing in PE for the transmission grid critically assumes that reliability of PE equipment is equal or better than conventional SVC technology. Early statistics indicate this is not the case and the 'gap' in reliability has both real economic and perceptual costs. If the existing 'un-reliability' of the VSC-based PE equipment is actually factored in, its likely 'cost' is in the range of $250-450k/year/FACTS site and effectively reduces the cumulative NPV of all benefits by more than 50%! This is a key opportunity for CEIDS/E2I to further their efforts that will directly help to accelerate the market penetration rates of PE. In addition, further efforts on substantial cost reductions of 20-30% would eliminate the only real competitive advantage that SVC possesses in comparison to VSC devices. Interestingly, two PE vendors indicated that at equivalent volumes, VSC products could be closely priced to conventional SVC devices. Similarly, even when trying to compare apples-to-apples on a performance basis SVC devices must be 'oversized' by 30% in order for them to perform to the same level of dynamic response as VSC equipment. Given the highly dysfunctional transmission investment marketplace that currently exists, these other attributes and benefits will not be recognized in the marketplace. Cost reductions are the only way to allow any value to be attributed to the many other strong performance attributes that PE equipment possesses.

If CEIDS/E2I are successful with both the reliability improvement and the cost reduction efforts, the marketplace for PE equipment would see a large acceleration in volume from the current rate of 1-2 sites/year and could achieve rates of 10-20 installations per year after a stabilization and 'acceptance' period of a couple years. This also agrees with the total marketplace calculation performed earlier of $100-200M/year for PE equipment to support leveraged reactive compensation requirements for a 2%/year average U.S. load growth. In addition, the total PE marketplace (including retrofit requirements) would be in excess of $5B which would represent another $100-200M/year of demand (depending upon build-out). In addition, if over the next couple of years, the "Problem of the Commons" is resolved to re-encourage marketplace incentives for transmission system investments, the total marketplace for PE equipment would increase by an additional factor of 2-3x. These volume increases are not just hypothetical since they were indeed achieved in the U.K. after transmission investment incentives were put in place which encouraged NGC to increase its transmission investments by over 300%/year over previous historical annual rates.

In addition to the project-level conclusions and recommendations presented in this report, the next steps are for regulators, legislators, and other government constituencies to work with utilities and more appropriately allocate potential risks and returns amongst transmission entity owners and their customers (society at large) to finally break this "Problem of the Commons" downward spiraling cycle. In the end, how these benefits are allocated must be negotiated effectively amongst all of these parties, but it is nevertheless clear that substantial and real value exist to society for implementing and accelerating these improvements. One can only hope that we do not have to wait for another Northeast blackout or terrorist attack on the grid to finally catalyze appropriate action.

APPENDIX A: BUSINESS CASE STUDY
The National Grid Company (NGC) and U.K. Transmission Investments

Prior to presenting a more detailed analysis of the business case for transmission grid investments, it is instructive to present a brief case study of the process by which the U.K.'s National Grid Company (NGC) greatly improved the performance of their electric national grid which allowed them to earn-out large pre-negotiated performance bonuses.

This case study of the NGC and the U.K. transmission grid is included in summary form in this report for several reasons. First, the NGC was in a similar position (as many U.S. utilities) with respect to deregulation, grid infrastructure deterioration, and lack of transmission investment incentives in the early 1990s. It was deregulated effectively in 1990 and operated a system that delivered over 40 GW average and 55 GW peak with 65 GW generation and over 8,500 miles of transmission lines. Over the last decade, the NGC has seen 20 GW of generation shut down and over 25 GW of new generation come on line, most of it in completely different locations. Also typically the grid operates with over 25 constraints per day and was primarily in need of power electronics for control of voltage stability and collapse. Secondly, the NGC was able to negotiate with their primary regulator a system of shared risks (losses) and benefits (bonus profits) for NGC demonstrating and achieving continued and quantifiable improvements in a number of key metrics having to do with what they called 'uplift'. Uplift included quantitative measurements for all of the following metrics:

- unscheduled power availability,
- power quality,
- generator errors
- reserve margins
- transmission constraints (TLRs and operation at peak)
- forecast errors
- 5 minute reserve
- ancillary services
- reactive power costs
- black-start capability

Between 1994-1996, these 'uplift' charges comprised over $1.15B/year in additional charges. Although the analogy does somewhat breakdown since NGC was negotiating with only one regulator whereas almost all U.S. utilities have several regulatory constituencies to deal with, the case is still applicable. Finally, the NGC over a period of 2-3 years began to make substantial new investments in their transmission infrastructure designed to allow them to maximize their expected incentives which were centered on those areas they had some or much control such as transport costs, transmission constraints, reactive power, and overall management of costs. After these investments were made, NGC commissioned a worldwide study of transmission system quality of service and delivery costs of other utilities around the world. In addition to many of the factors that have been mentioned earlier in this report for benefits of PE applications, the NGC sponsored survey used a number of metrics to establish service and costs indices. The construction of this kind of matrix is a tool often used in understanding competitive differences and advantages. An example of the Competitive Matrix representing the summary of the compiled competitive information from the survey done to measure utility transmission performance and service in the U.K., Europe, and the U.S. is shown in Appendix B. This method of evaluating the 'success' of specific players within an industry is to compare how that industry (e.g. transmission of electricity) in the U.S. compares to other global players. This method has the advantage of simplicity and often indicates the strengths and weaknesses of each player according to broad metrics. As indicated below, the U.S. transmission industry on average scores the worst in terms of both costs and level of service. Again, this kind of a metric is useful to point out that at least within the U.S., transmission market incentives and connection to the final customers are far from optimal which effectively argues for fervent lobbying to federal and state regulatory and governmental entities to try to restore a healthy balance again.

In fairness, this study was performed by UMS in 2001 out of the U.K. and was probably contracted by NGC so it might have some built-in biases. Nevertheless, it is probably broadly reflective of the average state of the transmission systems it sought to analyze at this time. Namely, the U.K. had just finished a massive upgrading of their system a few years before which resulted in a 37% real decrease in transmission operating costs while delivering a $72M/year maximum incentive bonus to NGC for achieving the maximum allowed incentive bonuses with their regulator for increasing system availability, reducing outages, improving quantifiable power quality, and the other metrics specified above; whereas in contrast, the U.S. had just experienced a decade of steadily declining transmission investments (from over $6B/year to under $2.4B/year) during a time when the difference between growing loads and transmission capacity actually increased by over 15%. As with the problem of the 'Commons' described earlier, the U.S. utilities were obviously incentivized to simply find ways of 'avoiding the wrath' of the public and their local regulators rather than delivering more reliable and higher quality power for which they would be fairly compensated. Informatively, the U.K. experience points out how powerful coming to a negotiated equilibrium can be for sharing losses and profits. The second business case analyzed in this report looks at the total 'pie' of total benefits to society and most other players as a way of expanding on the basic concepts that were described in this case study of NGC and the U.K. grid.

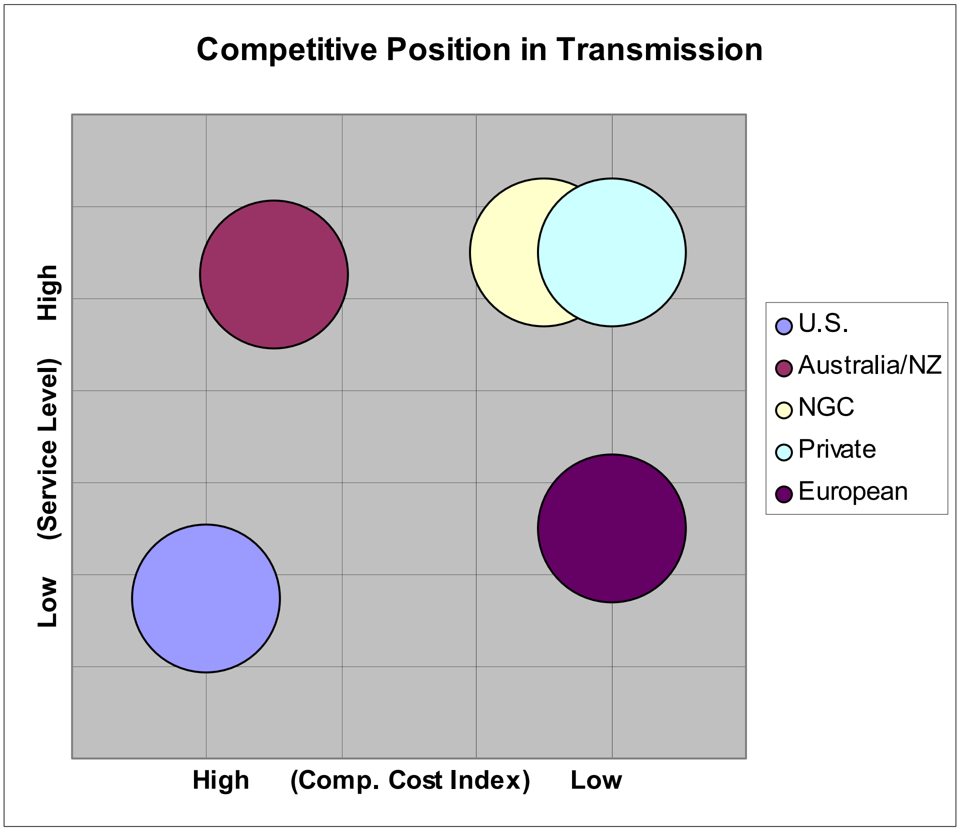

FIGURE 7: Competitive Position in Transmission

Figure 7 above is broadly indicative of the generalized failure of the U.S. transmission industry to improve costs and service quality over the last ten years. However, PE still has the ability to cost effectively impact many facets of this overall picture especially with respect to improving existing transmission corridor capacity and improving stability margins and voltage support. Because of incentives for sharing losses and profits, over a period of 2-3 years, NGC made over $400M in additional transmission investments, many of them using FACTS devices (although most were SVC-based applications).

APPENDIX B: Example Competitive Matrix for Transmission Investments

	Conventional Devices	SVC Devices Alternatives	VSC Devices Alternatives	Power System Scenarios (long lines, feed loss, short-circ 1st/2nd counting	Costs (Cap. Costs) (Life Cycle)	Costs (O&M, A&E) (TLRs?, (incr. Line loss)	Incr. Benefits (ROWs, Envir.) (Regul/Reliab)	Incr. Benefits (Performance) (Energy Svgs)	Incr. Benefits (Footprint,) (Reliability,)	Incr. Benefits (Reduced Outages (Synergistic)	Incr. Benefits Pre-fault Detect (DG/ wheeling)	Incr. Benefits (Sys Integ/Comm) (Incr. Cap)	Pot. Mkt $ (volume, $/unit) (turns/yr, mkt%)
FUNCTIONALITY													
CONTROL VOLTAGE													
	Load Tap Changers												
	MS Caps												
	MS Reactors												
	Series Caps												
	Gen. Excitation												
	Sync Cond.												
	Undervolt load shed												
	HVDC Converter												
VAR COMPENSATION													
	MS Shunt Caps												
	Ms Shunt Reactors												
	Series Caps												
	Sync Cond.												
CONTROL POWER FLOW													
	Series Caps												
	Series Reactors												
	Gen Dispatch												
	HVDC (tie-tie)												

TRANSIENT STABILITY

MS Braking Resistor

MS Series Caps

High Response Excit.

Early Valve Excit.

Gen Trip

Single Pole Switch

Line Sectioning

DAMP OSCILLATIONS

Power Sys Stabilizer

HVDC Modulation

Appendix B: EVALUATION MATRIX

APPENDIX C: Example Discounted Cash-Flow Matrix for Transmission Investments

		Yr-1	Yr-2	Yr-3	Yr-4	Yr-5	Yr-6	Yr-7	Yr-8	Yr-9	…….	Yr-20
Initial CapX+footprint		-2975	0	0	0	0	0	0	0	0	…….	0
Avoided costs	**7%**		225	241	258	276	295	0	0	0	…….	0
Environmental	**3%**		80	82	85	87	90	93	96	98	…….	144
System mgmt benefits	**3%**		100	103	106	109	113	116	119	123	…….	181
Power loops	**3%**		80	82	85	87	90	93	96	98	…….	144
Homeland security	**10%**		75	83	91	100	110	121	133	146	…….	505
Energy saved&power losses	**5%**		230	242	254	266	280	294	308	324	…….	610
Sys flex & gen/load uncertainty	**8%**		100	108	117	126	136	147	159	171	…….	466
Tangible & Intangible	**2%**		100	102	104	106	108	110	113	115	…….	149
Reliability & System stability	**7%**		125	134	143	153	164	175	188	201	…….	484
O&M/misc.	**5%**		(90)	(95)	(99)	(104)	(109)	(115)	(121)	(127)	…….	(239)
			891	**818**	**751**	**690**	**634**	**447**	**410**	**376**	**…….**	**149**
Net Present Value (NPV) ($k)		**7,758**										

APPENDIX D: List of Potential Metrics for Detailed Evaluation:

- Installed costs (equipment, installation labor, etc.)
- Equipment Commissioning costs
- Mean time between failures, MTBF
- Mean time to repair, MTTR
- Costs of Failure for each failure mode (scrap, rework, warranty, direct loss of sales time)
- Other Costs of Failure(mgmt/eng time, downtime, increased inventory, decr capacity, delivery problems, lost orders, etc.)
- Incremental % performance improvement for Capacity
- Incremental % performance improvement for Reliability
- Incremental % performance improvement for Security
- Incremental % performance improvement for Quality
- Incremental % performance improvement for Availability
- Operations & Maintenance costs/year
- Additional power losses due to internal equipment losses
- Footprint requirements & value
- Synergistic Benefits (system integration, contract power routing, system margin improvements, reactive power management value, no power loop flows, SCADA info, unique interface with grid of the future: DER, DG, ES, micro-grids, auto-isolation of house to grid, etc.)
- Efficiency % improvements (e.g. reduced heat losses or other local/system improvements)
- Life-Cycle Cost Analysis above simple Acquisition Costs (e.g. S/W, training, supply, support, disposal, pensions, indirect/support functions, etc.)
- Market size (units/year, total installed base, includes normal and accelerated turnover)
- Total Potential Market (includes both existing and potential units at a given/future pricepoint)
- Other Market Drivers (includes regulatory impacts, Investment Tax Credits, FERC cost recovery clarity)
- Power Outage/Quality Impacts and Value including GDP multiplier effects for specific industries
- Value Flexibility of Equipment and Functionality
- Preventative Maintenance requirements

- Pre-fault detection capabilities
- Component cost contribution of electronics (e.g. bill of materials and associated direct labor)
- Incremental improvement of cost components per year likely (ie tracks PE industry changes/yr)
- Additional Rights of Way issues (value, incremental usage that PE could provide)
- Other Regulatory incentives, processes and impacts
- Value of T&D cost avoidance
- Value of reduced tap changes for different applications (e.g. mech. switched capacitor banks)
- Value of less stress on power grid resulting in increased life of components
- Analysis of pros/cons of Mesh vs Radial Grid differences/impacts

APPENDIX E: Initial Framework for PE Transmission Investments

Business Case Outline: Targeted Transmission Applications (e.g. Capacity, Power Loop Flows, & Cost Avoidance):

(NOTE: Please see body of main report for more detailed information on this case.)

Brief Description

- Detailed analysis to identify bottlenecks and critical transmission corridors and nodes that would be most likely to benefit from PE applications (with respect to national security, grid reliability, and economic)
- The current U.S. power grid has been benefiting from the effective 'gold-plating' it received during the more regulated decades of the past, but those extra margins and reserves have now diminished to be point were many vulnerabilities exist
- Unlike much of western Europe, from the perspective of local operating requirements, the U.S. typically only requires continued power grid operation after only one fault (N-1) rather than two (N-2) so there is intrinsically more vulnerability.

Advantages

- Would provide solid bases both within a given utility and for local regulatory justification for making highly selected transmission investments and accelerate the process for decision making on these critical situations
- One of the primary purposes would be to galvanize regulatory organizations (e.g. DOE, FERC, and PUCs) around a number of 'critical' vulnerabilities to assist utilities in being able to move forward
- Perhaps this effort could also have the additional benefit of providing regulatory entities with the political justification for finally moving forward with reasonable economic incentives to utilities for making transmission investments
- Could be used as more cost-effective solution to brand new transmission corridors although would still be highly subject to 5-10 year load growth estimates (e.g. problems SDG&E has had in its transmission upgrade regulatory battles)
- In comparison to justifying new transmission or up-rating, the application of FACTS approaches can be both cost-effective and especially time-effective
- Would be instructive to note roles (+ or -) that Marcy substation might have had in August 14, 2003 Northeast blackout (e.g. some compensation, cascading, isolation, etc.) or the potential roles that such an installation would have had at critical points/interconnects.

Disadvantages

- Process is subject to all of the delays, pressures, and special interest effects and could greatly impact the timeliness of when these might actually be implemented
- Current cost per MVA and spotty reliability record has damaged more rapid acceptance of VSC-based applications
- Cost and complexity have limited market penetration and have limited market acceptance to the relatively small 'innovator' category
- Continued perception that reliability of a new transmission corridor is considerably higher than FACTS upgrading of existing corridor (e.g. 2 hrs/year vs 20hrs/year)

Key Market Issues

- Potential economic impacts are actually very large, but confusion over who reaps the benefits is large part of problem
- Pursuing relationships with the new Homeland Security department could greatly impact timing and other regulatory issues
- Several vendors indicated that VSC-based products would be equivalent in cost and pricing to SVC-based products if the volumes were comparable
- Even ABB stated that SVC is capable of VSC type dynamic responses if they are up-sized by 30% (which of course essentially makes them equivalently priced!)
- Anecdotal evidence suggests that the approximate value of increasing transfer capacity can be as low as $15k/MVA which is an excellent return and it is not uncommon in the range of about $100k/MVA which is similar to some anecdotal costs for new transmission corridor costs (depends strongly upon length serviced)
- Some key economic indicators include: (1) the annual value of increased transmission capacity could approximately be in the range of $12B/yr (assuming a 10% capacity factor and 15% utility carrying costs for return on assets); (2) the value of just reducing the power losses is approximately $800k/MW/yr which has a Net Present Value (NPV) ranging between $8-16M/MW; (3) power loops cost the impacted utilities at least $1-2k/MW; (4) the value of transmission corridor cost avoidance (if it is even possible to win regulatory approval for such new lines) is in the range of $1-3k/MW/yr (e.g. value of gaining 5-10 years of additional transmission usage).
- Cost of decreased reliability/availability could be $1-5k/MW/yr, cost of increased congestion and its impact on stability and reserve margins,
- Reduced O&M cost of .5-1%/yr comparing VSC to SVC (can it be improved over time with component count reductions?)
- Improved integrated protection and control 5-10% overall synergistic benefit (as is typical in systems integration studies),

- Reduced greenhouse gas emissions (CO2) worth 14,000 tons/yr/MW generated or saved,
- Other attributes such as: value of higher speed of control (ie fraction of power cycle vs 2-3 cycles), demand side management tools, with typical shunt capacitors a given voltage collapse is sharper and faster (ie 2x) without benefit of dynamic compensation, value of not operating at over-voltage for long periods (e.g. 1.05 pu at night), value of 50-60% reduction in footprint, greater control efficiency, active filtering, reduction of sub-synchronous resonance (SSR),
- Flexibility attributes include: assisting with distributed generation alternatives and tie-ins, improved grid operator tools, transmission congestion mgmt,
- Performance attributes include: ability to handle more transmission line relief requests (TLRs) which have increased by 250% over last four years, facilitating ‘retail wheeling’, in general loading transmission lines past their stability limits (SIL) results in a quadratic increase in capacitive reactive power compensation compared to only a linear increase in actual real power transfer, high temperature low sag conductors will require even greater VAR compensation, value of reduced ‘short circuit duty’, ability to increase series compensation past the typical 70% limit
- Future VAR compensation basic metric is load growth at 2%/yr real power growth (14,000 MW/yr) which requires approximately 4%/yr of reactive power compensation (9,000-16,000 MVAr/year) since VAR requirement increases as the square of the load which translates into $.3-1.1B/yr market, and if anecdotes of some generators installing reactive compensation to achieve unity power factor were generalized would imply total market of 200,000MVAr of need
- Example of transmission upgrades and incentives with NGC resulted in some additional components of T&D costs to be tracked and incentivized (unscheduled needs, HV constraints, LV constraints, generator shortfalls, cost of reserves, 5 minute reserve, reactive power, black start, primary response, and secondary response) were reduced by 9%($120M/year) and transmission investment increased 300% and realized 37% reduction in real transmission costs over less than five years once incentives were put in place, accommodation of frequent load and generation changes, increase system damping, decrease intrinsic power losses (from 1.5-2% to under 1%), etc.
- Seems to be sufficient unpublished anecdotal evidence that as many as 5-10 VSC-based applications would be economical per year. This rate would bring costs down to those of SVC-based applications.

Risks

- Normal delays and confusion where multiple government and special interest entities interact

Potential Obstacles

- Slow decision processes within many utilities and continued confusion regarding return on investment issues
- Uncertainty in future load projections and generation locations makes it difficult to really naildown potential PE requirements and benefits

Potential Accelerators

- Catastrophic failure(s) of the grid system due to N-1 or N-2 natural faults, or deliberate attacks by terrorists
- The Department of Homeland Security involvement could push key upgrades through swiftly if the sites were deemed in 'interest of national security'
- Greater co-funding and/or other incentives (ie tax credit, etc.) would have huge impact

Strategic Partners

- Potential government co-funding sources (Homeland Security, DOE, CEC, DOD?, etc.)
- Key vendors willing to put additional 'risk' capital at risk

Potential Impact of Northeast Power Outage:

- Should help to spearhead T&D investment by providing FERC sufficient political push to implement reasonable investment recovery mechanisms (e.g. accelerated depreciation, investment tax credits, 'fast-track' approval process for recovery from grid users, etc.)
- Emphasis on Grid Management and Control could further push benefits of FACTS (e.g. transmission failures in Ohio cascaded quickly through tie-lines and were not isolated as designed)
- Perform simulation analysis which might show that presence of PEs at critical locations have helped or "bought time" for helping to provide additional transient and dynamic stability to the grid (e.g. provide additional 10% transmission capacity on overloaded tie-lines thereby allowing them to remain in service)

Key EPRI/CEIDS role

- EPRI's ability to coordinate and fashion both consistent technical 'models' and financial models for how to evaluate the security/reliability/economic value of PEs

- Construct robust real-time ‘national grid simulator’ model for key infrastructure points which would greatly assist in providing an overall evaluation of the most appropriate criteria, bottlenecks, critical links, etc.
- Provide funding to really ‘tackle’ utility perception of PE reliability issues (e.g. both training and education as well as further R&D) to assure the control and auxiliary subsystems of PE products are as nearly ‘bullet-proof’ as possible.