Reassessment of Superconducting Magnetic Energy Storage (SMES) Transmission System Benefits

Technical Report

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REPORT SUMMARY

This report reassesses the benefits of superconducting magnetic energy storage (SMES) for enhancing transmission system performance.

Background
The first commercial application of SMES was in 1981 along the 500-kV Pacific Intertie, which interconnects California and the Northwest. The device's purpose was to demonstrate the feasibility of SMES to improve transmission capacity by dampening inter-area modal oscillations. Since that time, many studies have been performed and prototypes developed for installing SMES to enhance transmission line capacity and performance. A major cost driver for SMES is the amount of stored energy. Previous studies have shown that SMES can substantially increase transmission line capacity when utilities apply relatively small amounts of stored energy and a large power rating (>50 MW).

Objective
To re-evaluate SMES benefits for enhancing transmission system performance in light of recent changes in the electric utility environment (for example, electric utility deregulation and increased customer load growth), as well as technological improvements in both power converters and magnet systems.

Approach
A number of studies during the mid 90s investigated application of SMES to resolve transmission capacity constraints and enhance overall system performance. The project team reviewed nine previous studies of SMES benefits with respect to more recent changes in the electric utility environment. The reviews included interviews with original study participants. The team also attempted to "normalize" results of the previous studies to facilitate comparisons independent of methodology or assumptions. Four major topics were investigated:

- Why the proposed SMES devices were not installed when initially considered, and what would have to change to make SMES investment more likely today.
- Potential benefits of combining SMES with FACTS devices.
- The interplay between proposed Federal Energy Regulatory Commission (FERC) regulations and the deregulated utility environment.
- SMES benefits in a deregulated environment where energy prices can fluctuate across constrained transmission paths.

A cost-benefit model was developed in which the energy price differential across a constrained path was simulated and varied to evaluate the sensitivity of the investment. The frequency of

occurrence also was varied to determine investment sensitivity. In all, six business cases were studied.

Results

Study results indicated the following:

- The main reason for not investing in SMES was the uncertainty of the outcome of impending deregulation and recouping revenues in rates or through other mechanisms.
- In today's applications of Flexible AC Transmission System (FACTS) devices, the overall power rating could be reduced by adding SMES, resulting in a more efficient and versatile system for improving transmission system performance with added benefits off-setting the marginal cost increase.
- Due to the benefits of pooled resources, development of Regional Transmission Operators (RTOs) increases the possibility of investment in SMES and similar devices to enhance transmission systems.
- The six business cases all produced an average positive net present value. Five of the cases produced a rate of return on equity greater than 17%. However, only two cases had a breakeven on investment of less than five years.

EPRI Perspective

Small-scale SMES systems (<20 MVA) are already being effectively deployed for voltage support in distribution systems. However, based on previous work as well as the current study, EPRI believes that the most cost-effective market niche for SMES is for large-scale transmission system stability and throughput improvement. As a storage technology, SMES costs and power conversion system designs are optimized in comparison to other storage technologies when the power output exceeds 100 MW. While the future ownership and operating structure of the U.S. transmission system is still taking shape, what is certain is that transmission constraints do exist and that SMES with FACTS devices are one of a number of viable solutions for these constraints. Thus, EPRI recommends further research to identify locations where SMES-FACTS devices could be established to improve the transmission system and to establish the economic benefits for such applications. Additionally, research should explore the interactions between SMES magnets and the FACTS controller to determine the need for and design of viable protection and control systems. This research will benefit utilities, RTOs, and FERC itself, to help them build a power grid that is responsive to the needs of the 21st Century.

Keywords

Superconducting magnetic energy storage (SMES)
FACTS
Transmission stability improvement
Energy storage
Transmission constraints
Utility deregulation

ABSTRACT

This report summarizes a study that reassesses the benefits of superconducting magnetic energy storage (SMES) for enhancing transmission system performance for utility systems. A number of studies were conducted during the mid 90s to investigate application of SMES to resolve transmission capacity constraints and enhance overall system performance. A number of key issues have changed since those studies were conducted, including electric utility deregulation, increased customer load growth, and technological improvements in both power converters and magnet systems. This study revisits those previous studies of SMES benefits in light of these changes in the electric utility environment. The study also attempts to "normalize" the previous studies' results to facilitate comparisons independent of methodology or assumptions.

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1 INTRODUCTION

The concept of using Superconducting Magnetic Energy Storage (SMES) to enhance electric transmission system performance was first conceived during the late 1970's. In fact the first commercial application of SMES was in 1981 and located along the 500 kV Pacific Intertie which interconnects California and the Northwest. The purpose of this device was to demonstrate the feasibility of SMES to improve transmission capacity by dampening inter-area modal oscillations. Since that time many studies have been performed and prototypes developed for installing SMES for enhancing transmission line capacity and performance. This report summarizes an effort to re-evaluate the benefits of SMES for enhancing transmission system performance in light of recent changes in the electric utility environment.

SMES has many potential applications. However one of the main cost drivers is the amount of stored energy. Previous studies have shown that for application of relatively small amounts of stored energy, and large power rating (i.e. >50 MW) SMES can result in substantial increases in transmission line capacity. The following studies are referenced in chapter 7 of this report.

Studies Reviewed

- Southern California Edison SMES Benefit Evaluation Study, May 1996 [Ref 1]
- Evaluation of Superconducting Magnetic Energy Storage At Blythe, July 1995 [Ref 2]
- Superconducting Magnetic Energy Storage Benefits Study for San Diego Gas and Electric Co., June 1996 [Ref 3]
- Superconducting Magnetic Energy Storage Utility Applications In New Mexico, October 1994 [Ref 4]
- West Coast Utility Transmission Benefits of Superconducting Magnetic Energy Storage, January 1996 [Ref 5]
- Superconducting Magnetic Energy Storage Benefits Assessment For Niagara Mohawk Power Corporation, February 1995 [Ref 6]
- Analytical Studies To Demonstrate Additional FACTS Technologies on the New York State Transmission System, May 1996 [Ref 7]
- Superconducting Magnetic Energy Storage (SMES) Utility Applications Studies, Wisconsin Electric Power Co, October 1995 [Ref 8]
- Utility Benefits of SMES in the Pacific Northwest, September 1996 [Ref 9]

This study revisits those previous studies and updates them in light of electric utility deregulation, system changes, and technological improvements that have taken place since they were done. The issue of compatibility of SMES and FACTS is also examined, and the possible synergistic benefits that can be obtained by combining them. A new cost/benefit model is developed and used to evaluate the cost effectiveness of SMES.

2
BENEFITS OF SMES TO ENHANCE TRANSMISSION SYSTEM PERFORMANCE

Implementation of SMES can improve transmission system performance in many ways. Table 1, below, provides a list of the identified benefits that SMES can provide for the transmission system. Each of these benefits were identified and analyzed in previous studies. A discussion of each of these benefits follows the table.

Table 2-1
Summary of SMES Transmission System Benefits

Benefit	Description
Transmission Stability Damping	Increase the transmission load carrying capacity by improving long-term dynamic stability performance.
Transient Voltage Dip Improvement	Increase the transmission load carrying capacity by reducing the transient voltage dip following a system disturbance.
Dynamic Voltage Stability	Improve transmission transfer capability by improving voltage stability margins.
Tie Line Control	Minimize area control error (ACE) through active frequency regulation.
Spinning Reserve	Reduce the amount of generation required to spin for emergency backup spinning reserve requirements
Load Leveling	Displace high cost generation during peak load periods, both capacity (MW) and energy (kWhr) benefits.
Under frequency Load Shedding Reduction	Reduce under frequency load shedding during large system disturbances through injection of real power.
Circuit Breaker Reclosing	Allow reclosure of circuit breakers at high angular displacement following major disturbances.
Power Quality Improvement	Reduce voltage dips and provide real power ride through capability during disturbances.
Backup Power Supply	Provide backup power supply to large customers.
Sub-Synchronous Resonance Damping	Increase transmission line capacity by allowing higher levels of series compensation by providing active sub-synchronous damping

Stability Damping

Power system stability limitations are often characterized by low frequency oscillations (0.5 – 1 Hz) following a major system disturbance. Power transfers are often limited to prevent growing oscillations from occurring following loss of a single major transmission line or generator. When limited by long-term stability the transmission capacity can be increased by providing active damping of these oscillations. SMES can actively dampen these system oscillations through modulation of both real and reactive power. Studies have shown that because SMES can modulate real power, as well as reactive power, it can be much more effective, and smaller in size, than other technologies. Figure 1 shows a plot of system voltage oscillations with increased power transfers of 400 MW, system undamped with a 400 MW SMES and well damped with a 450 MW SMES, this illustrates how effective SMES can be to dampen oscillations.

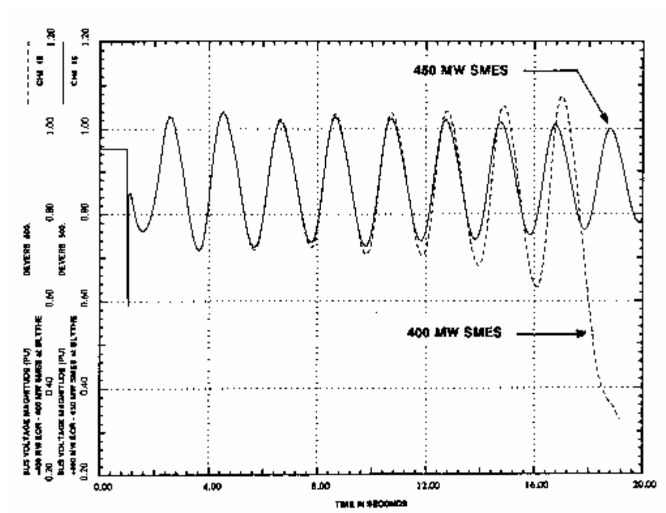

Figure 2-1
Effectiveness of system damping with a 400 MW and 450 MW SMES

Transient Voltage Dip Improvement

A transient voltage dip lasting for 10-20 cycles can result when a major disturbance occurs on the power system. The California Independent System Operator (CAISO) limits the power transfers from Arizona to California in order to reduce the duration and magnitude of voltage transients. For the Southern California system the maximum allowable voltage dip as measured on the bulk power transmission system can be no greater than 25%, and can last no more than 20 cycles. SMES and associated converter equipment has been shown to be effective for providing voltage support which can result in increasing the power transfer limitations on the transmission system.

Dynamic Voltage Stability

Dynamic voltage in-stability can occur when there is a major loss of generation or heavily loaded transmission line and there is insufficient dynamic reactive power to support voltages. Voltages will degrade slowly over time in the 5-15 minute time frame (sometimes faster) and can result in a voltage collapse. SMES has been shown to be effective in mitigating dynamic voltage in-stability by supplying real and reactive power, simultaneously supplanting loss of generation or a major transmission line. Depending on the energy storage capability and the reactive power rating of the converter, SMES can stabilize the system long enough to allow generators or other reactive power sources to come on line and prevent voltage instability. This improvement in performance can result in increased power transfer limits on the transmission system.

Tie Line Control

When power is scheduled between utility control areas it is important that the actual net power matches closely with the scheduled power. Unfortunately when generators are ramped up in one control area and down in the receiving control area to send power, the system load can change causing, an error in the actual power delivered. This Area Control Error (ACE) can result in in-efficient use of generation. SMES can be designed with appropriate controls to inject power to virtually eliminate this error and insure that generation is efficiently used and power schedules are met.

Spinning Reserve

In case a major generating unit or major transmission line is forced out of service a certain amount of generation must be kept unloaded as "spinning reserve" to make up for the lost generation. Most operating guidelines require that this spinning reserve be as much as 7% of the system load or the largest single contingency. Since SMES can store a significant amount of energy it is possible to rely on SMES to provide enough "spinning reserve" to meet the requirement until gas turbine generators can be brought on-line. Providing "spinning reserve" with SMES is much more efficient since it is a virtually lossless form of storage, whereas providing spinning reserve with generation has significant losses.

Load Leveling

The cost of producing energy varies throughout the day depending on the type of generation dispatched and the associated fuel cost. The highest cost energy is produced at peak load periods while the lowest cost energy is produced during off peak periods (e.g. nighttime). Load leveling is performed by storing low cost energy during off-peak periods and returning energy and capacity on-peak. This benefit is realized when SMES gains credit for both converting low-cost energy into higher-value energy and its ability to defer the acquisition of high-cost generating resources. Studies have shown cases where SMES can have a large net present worth when it can replace the need to acquire combustion turbine units of similar capacity.

Underfrequency Load Shedding Reduction

When the power system suffers the loss of a major resource such as a generating plant or major importing transmission lines the system frequency will drop and continue to decline until the generating resource – load balance is restored. To prevent loss of synchronism and total blackout of the system, protective relaying has been installed to detect the frequency decline and trip customer load off-line (i.e. load shedding). Because SMES can inject real power rapidly into the system it is an effective method to offset, or reduce, under frequency load shedding because it reduces the mismatch between load and supply capability of the system disturbance.

Circuit Breaker Reclosing

Following clearance of a fault, circuit breakers attempt to reclose and return the affected transmission line to service. This is accomplished routinely whenever the power angle difference across the circuit breaker is within acceptable limits. However, protective relays prevent the circuit breaker from reclosing if the angle difference is too large. By briefly supplying some fraction of the power normally transmitted by the transmission line, SMES can reduce the power angle difference across a circuit breaker and allow reclosure of the circuit breaker. This allows restoration of the system power transfers quickly following outages of major transmission lines.

Power Quality Improvement

SMES can provide ride through capability and smooth out disturbances for power systems that would otherwise interrupt sensitive customer loads. When momentary disturbances such as transmission line flashovers or lightning strikes occur, power can be lost if the transmission line trips or voltages can dip low. SMES has very fast response and can inject real power in less than one power cycle preventing important customers from losing power.

Backup Power Supply

The energy storage capacity of SMES can be used as a back up power supply for large industrial customers in case of loss of the utility main power supply. Studies have shown SMES can be sized with the appropriate energy storage and capacity to provide back up through most disturbances and be cost effective.

Sub-Synchronous Resonance Damping

Generators which are connected to transmission lines which have high levels of series compensation (series capacitors) can be exposed to a phenomena called Sub-Synchronous Resonance (SSR) which can result in serious damage to the generator. In most cases series compensation levels are limited to levels that do not result in possible exposure of generators to SSR. Unfortunately this also often limits the transfer capability of the transmission system. SMES as an active device can be designed to provide mitigation of SSR and allow higher levels of series compensation to be installed.

3
PREVIOUS SMES BENEFITS STUDIES

The following section provides a brief summary of previous studies that were performed to determine the benefits of installing a SMES for various applications on the transmission system. Several of the studies focus on the applicability and cost effectiveness for applying SMES to increase transmission capacity by improving system stability and first swing transient voltage dip. Others focus on the ability of SMES to provide load leveling, spinning reserve, and backup power for large industrial customers. Most of studies did examine economics and, in most cases, evaluated cost effectiveness on a present value basis. The cost estimates for SMES in all of the following reports were based on the EPRI SMES Cost Estimate model provided in [ref 10]. The Energy Price Differential and Energy Price Frequency are unknown for these previous studies, however at the time the studies were performed energy prices were in the $ 30-40/ MWhr price range.

Review of Previous Studies

SMES Benefit Evaluation Study (Southern California Edison SMES Benefit Evaluation Study)

This study, conducted by Southern California Edison Co. during 1996, under EPRI funding (WO4187-04), focused on increasing the transmission system transfer capability from Arizona to California. The study specifically focused on reducing the transient voltage dip following loss of the Palo Verde – Miguel 500 kV transmission line by installing a SMES. The study results indicated that the Arizona to California (East of River) transfer capability could be increased by 500 MW by installing a 650 MVA SMES with about 360 Mega joules of energy storage capacity. However, the study did not simulate proper existing voltage support provided by shunt capacitors, and as a result the SMES may be sized too large. The study indicated that at low power transfers the real power output by SMES might be more effective. At high power transfers the reactive power output from SMES is more effective. The computer model used in the study needed to be improved to capture the benefits of real power injection by SMES. The study simulated SMES at only one location, the Devers substation near Palm Springs, Ca..

No cost/benefit analysis was done or comparison of costs/benefits to other technologies. The study did perform a validation of the SMES computer model developed for EPRI's Extended Transient and Midterm Stability Program (ETMSP) and software from Power Technologies Inc. (PTI). This provides confidence in not only the results of this study but other studies that used both the ETMSP and PTI program to conduct dynamic simulations. The study also demonstrated through eigenvalue analysis that proper tuning of the SMES control system is important.

Table 3-1 summarizes the results of the study. The transmission increases are on the Arizona – California transmission path. The study also identified transmission enhancement that could be achieved along the West of the Colorado River path, which includes generation from Nevada; this is summarized on Table 3-2. In all of the following cases the energy storage capacity required is less than 200 kWhr. It should be noted that in order to achieve these benefits thermal overload and voltage stability constraints must be resolved. The SMES has no control over power flows and thus cannot resolve transmission thermal overload constraints. System voltage collapse cannot be resolved by the SMES modeled in this study since the proposed locations are significantly away from the voltage collapse point.

Table 3-1
Results of SMES Benefit Study by Southern California Edison

Arizona – California Transmission Capacity Enhancement

Transmission Capacity Increase (MW)	SMES Power Rating (MVA)	Real Power Output Required (MW)	Reactive Power Output Required (MVAR)
200	190	184	49
500	630	361	516
700	1080	369	1015
1000	2080	539	2009

Table 3-2
Results of SMES Benefit Study by Southern California Edison

West of River Transmission Capacity Enhancement

Transmission Capacity Increase (MW)	SMES Power Rating (MVA)	Real Power Output Required (MW)	Reactive Power Output Required (MVAR)
500	390	251	299
1000	2170	562	2096

Evaluation of Superconducting Magnetic Energy Storage At Blythe (San Diego Gas and Electric Co.)

This study, funded by SDG&E and performed by Battelle Northwest Laboratories in 1995, examined the feasibility and determined the benefits of installing a SMES at San Diego Gas and Electric's Blythe site located near Blythe, Ca.. The concept was to install a SMES at this site and loop in the nearby Palo Verde – Devers 500 kV transmission line. The main purpose of this device was to increase transfer capability on the Palo Verde – Devers and Palo Verde – Miguel 500 kV transmission lines by improving power system damping following loss of a major transmission line. At the present time the Arizona – California power transfer capability is limited by both voltage and stability limitations. The stability limitations are primarily determined by sustained or growing oscillations following a three-phase fault and loss of the Palo Verde – Miguel 500 kV transmission line. Study results indicated that a 300 MVA rated SMES could increase Arizona – California transfer capability by 400 MW, assuming that voltage limitations and conductor thermal limitations could be improved. The study was conducted in two phases, Phase I investigated the benefits of increasing Arizona – California power transfer capability, Phase II investigated multiple benefits including most of those identified on Table 2-1 of this report. The computer model was a very simple model using a power converter with modification of a resistive brake using EPRI's ETMSP program. Results confirmed the NYPA study (which was conducted at a later date see below), that real power injection for stability damping is more effective when located near a generating site. Reactive power injection (i.e. with STATCOM or SVC) is more effective when further from the generation resource that is involved in the swing mode. Study results indicated that for the location at Blythe a 60º real – reactive (P-Q) power relationship for power modulation was the most effective. The study also investigated limiting the duration of the action of the SMES to 10 seconds. Results indicated that power transfer capability was reduced with shorter time duration. The study not only examined Blythe, but also conducted prony analysis for damping effectiveness at other sites. Table 3-3 shows a summary of Arizona – California transmission capacity increase. It should be noted that in order to achieve these benefits thermal overload and voltage stability constraints must be resolved. Recently, projects have bee proposed to install additional series compensation and possibly FACTS devices to increase the thermal capacity of the Arizona – California transmission system. New transmission lines have also been proposed to resolve transmission constraints from the Four Corners area to California.

Table 3-3
Summary of Arizona – California Transmission Enhancement

SMES Converter Rating Located at Blythe	Arizona – California Transmission Enhancement (MW)	
	Real Power Modulation Only	Reactive Power Modulation Only
500 MVA	300	>511
900 MVA	407	>511

A SMES with a capacity rating as large as 900 MVA, and a energy rating of 1 MWhr was also studied. The benefits for reducing spinning reserve, load leveling and reduction in under frequency load shedding was analyzed. Economic analysis including all of the benefits and the estimated cost of the SMES was conducted. Results indicated a high net present value favoring development of the SMES. Table 3-4 provides a summary of the economic cost effectiveness of SMES for this application. Note that net present value of $ 82 – 135 Million is considerably greater than the $ 45 – 60 Million capital cost of the SMES.

Table 3-4
Summary of a 500 MVA (1 MWhr) SMES

Benefit	Unit Value ($ x Million)	Present Value of Benefits ($ x Million)
Transmission Enhancement/yr	5- 6.7	69 – 92
Voltage Control (Avoided Capital)	0.3 – 12.5	0.3 – 12.5
SSR Damping (Avoided Capital)	2 – 7	2 – 7
Tie Line Control/yr.	0.5	6.9
Spinning Reserve/yr.	0.07	0.94
Load Leveling/yr.	0.001	0.014
Under frequency Load Shedding/occurrence	2 - 5.7	2.8 - 16
Total		**82 - 135**

Superconducting Magnetic Energy Storage (SMES) Benefits Study (San Diego Gas and Electric Co.)

San Diego Gas and Electric conducted this follow up study with funding and support from the Electric Power Research Institute to further evaluate the benefits of utilizing SMES to increase the Arizona – California and Southern California Import Transfer Capability (SCIT). This study utilized a much more sophisticated computer model of the SMES and associated power converters using EPRI's ETMSP. Results of this study produced similar results to the previous studies, showing that a 475 MVA SMES could increase Arizona – California transfer capability by more than 500 MW, if thermal conductor and voltage limitations were resolved. This study also compared SMES performance for damping to a STATCOM. Results indicated that a 675 MVA STATCOM would be required to achieve the same 500 MW increase in transfer capability. These results coincide with previous studies indicating that combination of real and reactive power injected by SMES can result in an overall smaller device than FACTS alone while providing even more benefits. This study also addressed both the stability damping and first swing transient voltage dips, which both can limit Arizona – California and SCIT power transfer capability. The following Table 3-5 summarizes the results of this study. It should be noted that in order to achieve these benefits thermal overload and voltage stability constraints must be resolved.

Table 3-5
Summary of SMES Benefits Study (San Diego Gas and Electric Co.)

Transmission Enhancement Arizona – California (MW)	Transmission Enhancement Southern California Import (MW)	SMES Rating (MVA)
500	0	475
650	0	630
200	300	325
200	900	400

Superconducting Magnetic Energy Storage (SMES) Utility Applications In New Mexico

Oak Ridge National Laboratory sponsored several studies investigating the benefits of SMES in utility applications, for the U.S. Department of Energy and the Defense Nuclear Agency. This study, conducted by Pacific Northwest Laboratories, evaluated SMES on the Public Service Company of New Mexico (PNM) and El Paso Electric (EPE) utility systems. Two load leveling applications were examined one in each of the utilities service territories. Results indicated that SMES could be cost effective for load leveling if it could displace the need for future peaking generating units. The study examined and quantified the benefits for generating capacity deferral, energy savings, automatic generation control, and voltage regulation. About 80% of the benefits were due to generation capacity deferral and energy savings. The improved benefits of automatic generation control accounted for the remaining benefits with almost no benefit identified for voltage regulation.

In addition, this study also examined a unique application of SMES for allowing circuit breaker reclosing under high angle separation conditions. Results indicated a $ 580,000 benefit per year for circuit breaker reclosing. This provides significant potential reliability benefit by allowing quick restoration of major transmission lines following disturbances. The study also examined potential SMES applications at the White Sands Missile Range. No significant benefits were identified to justify installing a SMES at White Sands.

West Coast Utility Transmission Benefits of Superconducting Magnetic Energy Storage

The utilities along the West coast including Bonneville Power Administration, Pacific Gas and Electric Co., Southern California Edison, Los Angeles Department of Water and Power, Western Power Administration, and San Diego Gas and Electric Co. participated in a study sponsored by EPRI to investigate the potential benefits of SMES on the utility transmission system in the Western region. This study investigated potential benefits along all the major bulk power transmission paths in the Western system. Including the SCIT, Arizona – California (East of River), West of River (WOR), the AC Pacific Intertie, and the DC Pacific Intertie,. Results indicated that the Arizona – California transfer capability could be increased the most with a SMES with a size of 300 MW. Table 3-6, below, summarizes the study results.

Table 3-6
SMES Benefits West Coast Utility Study

Transmission Enhancement (MW)	SMES Size (MW)	Benefit Present Value ($M)	SMES Modulation	
			Capital Cost ($M)	Net Present Value ($M)
100	50	$ 13.8	$ 18.5	$ -4.7
300	100	$ 41.3	$ 30.1	$ 11.2
500	300	$ 68.8	$ 42.4	$ 26.5

This study also discussed other multiple benefits of SMES and further pointed out that a single – purpose SMES application may not be cost-effective when compared to alternate technologies, however it is likely that inclusion of these other multiple benefits, as shown in Table 1, could make SMES more cost-competitive.

Superconducting Magnetic Energy Storage (SMES) Benefits Assessment For Niagara Mohawk Power Corporation

This was another of the studies sponsored by Oak Ridge National Laboratory to evaluate utility applications of SMES. The study evaluated three possible applications on the Niagara Mohawk Power Corporation's system; all of them were related to providing backup power. One application was for providing back up power for a large industrial customer (large paper mill) with about 32 MW of load that had been interrupted numerous times due to lightning strikes and flashovers on the transmission system that serves the customer. The size of the SMES for this application was only about 30 MW with an energy rating of 30-300 MJ. Niagara Mohawk decided to install conventional lightning arresters and improve static wire shielding to reduce lightning induce power interruptions.

The other two applications involved providing backup power to area loads which were served by radial transmission lines to remote areas (Lake Placid, and Tupper Lake). The energy rating of SMES for these applications was rather large 50- 1500 MWh making them very costly.

Economic analysis was provided for all of the scenarios. Results indicated that the benefit/cost ratio was less than one (indicating cost is greater than the benefits) for all of the scenarios. Table 3-7 provides a summary of the cost/benefit of these SMES applications.

Table 3-7
Summary of SMES Applications At Niagara Mohawk Power Corp.

Application	SMES Size (Stored Energy/ MW)	Present Worth of Benefits ($ x Million)	Cost ($ x Million)	Benefit/Cost Ratio
Champion Paper Mill	30 MJ / 10 MW	6.76 – 13.22	1.75	3.9 – 7.6
	300 MJ/ 30 MW	13.53 – 26.44	6.75	2 – 3.9
Lake Placid	1500 MWhr/ 100 MW	263	1364	.19
Smaller Storage	250 MWhr/100 MW	263	390	.67
Alt. W/ diesel gen.	50 MWhr/ 100 MW	263	189	1.4
Tupper Lake	550 MWhr/ 19 MW	89.7	653	.14
Alternative	174 MWhr/ 19 MW	89.7	303	.3

Analytical Studies To Determine Additional FACTS Technologies on the New York State Transmission System

This study, sponsored by EPRI and conducted by Power Technologies Inc., focused on increasing power transfer capability across the state of New York from the Northwest portion of New York to the Southeast portion. Generally the large generating resources and import tie lines are located in the Northwest and the large system loads are located in the Southeast. The system transfer capability is limited by voltage stability and transient stability. Various Flexible AC Transmission Systems (FACTS) and non-FACTS devices were investigated to improve system voltage and transient stability. Study results indicate that all of the FACTS devices (STATCOM, SMES, BES, UPFC, and TCSC) and conventional device (SVC and PSS) can effectively increase transfer capability. Economic analysis indicated that Power System Stabilizers (PSS) is the least cost option. However, other additional benefits provided by SMES and FACTS devices may justify them. Further analysis of these benefits was suggested.

The study did evaluate SMES connected to a STATCOM and determined that additional benefits do exist with SMES over other technologies. SMES also provides additional flexibility to adapt to changing network conditions, which is an important feature that a storage device brings to system operation. The study also showed that SMES benefits for damping system oscillations are most effective when located near a generating resource, which also verified the results of previous studies.

Superconducting Magnetic Energy Storage (SMES) Utility Applications Studies (Wisconsin Electric Power Co., ORNL)

This study focused on the benefits of using SMES to improve transient stability and reduce or eliminate the need for tripping generation. Two cases with SMES modeled were considered, along with alternatives using a braking resistor in combination with SMES and using Power System Stabilizers (PSS) on existing generators instead of SMES. Results of this study indicate that SMES is very effective for resolving the stability problems associated with the Northern Wisconsin Electric Power Grid. The size SMES units under consideration were a 50 MW power capacity, with energy output duration of 0.5 seconds. Power System Stabilizers (PSS) were almost as good as the SMES for mitigating the transient stability problems. Economic analysis indicated that only the PSS had a positive net present value using a discount cash flow analysis.

Table 3-8
Summary of SMES Application Studies (WEPCO)

Application	SMES Size (Stored Energy/ MW rating)	Cost ($ x Million)	Net Present Value ($ x Million)
Presque Isle Gen. Transfer	100 MJ/50 MW	6.5	$ - 6.7
Point Beach Wobble	250 MJ/50 MW	7.5	$ - 6.9
PSS at Point Beach	NA	$ .124	$ .039

Utility Benefits of SMES in the Pacific Northwest (Battelle Northwest, EPRI)

This study analyzed several different applications of SMES in the Northwest power grid.

One of the unique things that this study considered was application of large scale load leveling using a SMES with 1000 MW of power output capacity. Sensitivity analysis of natural gas prices was performed using EPRI's Dynastore production costing program. Results indicated that natural gas prices would have to reach $ 4/MBtu for a 1000 MW, 1 hr. SMES to have a net positive present value. Interestingly, the present cost of natural gas is about $ 4.5/Mbtu. Also, the capital cost of a natural gas fired combustion turbine was assumed as $ 634/kw whereas today the cost is abut $ 250/kw. These may be two offsetting issues when examining the benefits of SMES in today's market.

Interview With SMES Investigators

Interviews were conducted with various persons involved in the previous SMES benefits studies. The purpose of these interviews were to gain insight into three main issues:

1. Identify the reasons that the SMES units were not installed.

2. What are the key issues that would have to change to make SMES viable for future installations?

3. Does SMES become a competitive choice in a deregulated electric energy market?

Interviews were conducted with representatives of EPRI (which sponsored five of the eight studies), Pacific Northwest Laboratories (which performed three of the previous benefit studies), Southern California Edison, and San Diego Gas and Electric Co. In addition discussions were held with representatives of American Electric Power and BWXT, which are considering installing a SMES at the Inez UPFC in Kentucky. Additional interviews were held with other industry and utility personnel that were involved in previous studies and installations of SMES. The following people were interviewed as part of this study:

Ed Arguello (Public Service of New Mexico Co.)

Glenn Cambell (BWXT Technologies)

Dr. Paulo Ribeiro (BWXT Technologies)

Dr. Juris Kaugerts (BWXT Technologies)

Mr. C.M. Weber (BWXT Technologies)

Mr. John DeSteese (Battelle Northwest Labs.)

Steve Eckroad (Electric Power Research Institute)

William Hassenzahl (Advanced Energy Analysis)

Gerald Keane (Siemens PT&D)

Mohan Kondragunta (Southern California Edison)

John Stovall (Oak Ridge National Lab.)

In addition to those listed above other individuals with expert knowledge of the deregulated electric energy market provided insight and comments. The following is a summary of these discussions on the above three topics as well as other insights. Additionally, the author of this report was a principal in the SDG&E studies and his insights are included.

The reasons that the SMES units were not installed.

The reasons that SMES was not installed were many and varied depending on utility and region, but they all had a common underlying theme. During mid 1990's (i.e. 1994 – 1997) when these studies were undertaken the economy was just emerging from recession, which resulted in reduced load growth. In addition there was much discussion about deregulation and the creation of open access to the transmission system. There was considerable pressure by the Federal Energy Regulatory Commission (FERC) and state utility commissions to break up the vertically owned utility companies and create a deregulated energy market. There was, and still is, considerable doubt about recovery of stranded assets owned by utilities. Thus a great deal of risk was created for utilities to invest significant additional capital in anything until a method of recovery of stranded assets and a mechanism for obtaining a return on any future investments was established. This made building any significant capital improvement in the transmission system infrastructure almost non-existent. Despite studies showing significant positive net present value, these changing market pressures and high-risk level due to the uncertainty of looming deregulated market made investment not only in SMES but any significant investment difficult at best. It is interesting to note that during the period of 1994 – 2000 not one single new major bulk power transmission line was built by a utility in the United States. Also, every major generating station built during that time frame was developed by private entities. In California no new transmission or generation resources have been installed in the last ten years.

What are the key issues that would have to change to make SMES viable for future installations?

As the ground rules for rate recovery for transmission investments and mechanisms for recovery of stranded assets is established, utilities will start a re-investment and upgrade of the transmission systems, which are so desperately needed. In California, for example, the uncertainty of development of the ground rules for deregulation has created a significant reliability risk, due to the delay in building generating resources as well as transmission lines to meet the growing load demand. During the late 90's the economy picked up and the load growth along with it, and California (indeed the whole Western system) now finds itself barely able to meet the load demand. In fact during the summer of 2000 the California Independent System Operator (CAISO) had to drop interruptible load 13 times to prevent rolling blackouts.

One investigator pointed out that based on energy storage alone, for load leveling, that his earlier study had projected at what level natural gas prices would have to reach for SMES to be cost competitive. He noted that gas prices have risen and today (mid-2000) are at or above the levels predicted in his study.

In addition, three of the studies which identified the main benefit of SMES as increasing transmission capacity, through stability damping and reduction in transient voltage dip, were based on the expected cost differential between on-system generation costs and purchasing additional off system generation. That cost difference (about $ .005 kWh at the time of the studies) has risen sharply in the last couple of years. This would increase the benefits dramatically, making SMES a much more attractive choice.

Does SMES become a competitive choice in a deregulated electric energy market?

As the system reliability risk gets greater and the assurance of recovery of investments is established, utility investment in the transmission system will occur. In fact, licensing and plans for construction of significant new bulk power transmission including FACTS devices are now underway in California. Since California is about two years ahead of most of the states in the U.S. (in regard to electric energy market deregulation), and as the rate recovery and market rules get worked out, we may very likely see a trend in increased capital investment in the transmission systems throughout the U.S. in the next few years.

Because SMES has multiple benefits, due to its ability to store and deliver real power as well as reactive power, as opposed to a single purpose FACTS device, it could become a very viable choice for system performance improvement. And as ancillary services markets are developed in the deregulated markets, additional benefits may be realized for marketing and capturing benefits of all of the performance enhancing features of SMES including spinning reserve, black start capability, and voltage support.

Reassessment of SMES Studies

All of the SMES benefits studies previously discussed in section 4.1 of this report attempted to quantify the economic benefit. Table 3-9 is an attempt to put all of the results of these studies on a "common terminology" basis to allow ready comparison among the various studies. Net present worth is shown as an economic comparison since it was used in most of the studies. However, as will be discussed later on development of an economic model (see section 6) Return on Equity (ROE) is considered to be a better investment evaluation measure than net present worth. In all cases the present worth is calculated using an assumed 30-year life and 10% discount rate. All costs and benefits are shown in year 2000 dollars.

Results of this comparison indicate that the application of SMES for transmission enhancement has the greatest positive net present value. The application of SMES to provide backup power to industrial customers also has a significant positive net present value. Only one case for load leveling and supplying a large aggregate load indicated a net positive present value. Interestingly, the application of spinning reserve always resulted in negative net present value. Whereas the only case evaluated for tie line control indicated a positive net present value.

Table 3-9
Comparison of SMES Benefit Studies (Year 2000 $)

Application	Study Report (See References)	Power Capacity Rating (MVA)	Business Case No.	Stored Energy Requirement	Benefit ($ x Million)	Cost (1) ($ x Million)	Net Present Worth ($ x Million)	Average NPV for Business Cases ($ x Million)
Load Leveling	4	400		400 MWhr	180.3	193.6	-13.3	
	2	150		150 MWhr	134.5	208.2	-73.7	
	7,4 (4)	100		100 MWhr	54.0	84.3	-30.3	
	7,4 (4)	100		400 MWhr	123.7	171.9	-48.2	
	2	20		20 MWhr	26.1	87.2	-61.1	
Transmission Enhancement	2	900	1	1 MWhr	145.1	86.8	58.3	41.9
	2	500	2	1 MWhr	80.7	50.9	29.8	31.1
	5	480	3	133 kWhr	80.5	49.6	30.9	56.6
	3	325		.5 MWhr	32.2	40.7	-8.5	
	5	260	4	72 kWhr	48.3	35.2	13.1	32.3
	2,5	80		22 kWhr	16.1	21.6	-5.5	
Tie Line Control	2	30	5	5 MWhr	87.7	56.2	31.6	1.6
Spinning Reserve	2	150		150 MWhr	86.0	208.9	-123.0	
	2	26		26 MWhr	12.2	86.0	-73.8	
	2	16		16 MWhr	9.6	71.2	-61.7	
Industrial Power Backup	6 (3)	30		83.3 kWhr	16.4	8.3	8.2	
	6 (3)	10		8.33 kWhr	8.3	2.1	6.1	
Large Aggregate Load	6	100		50 MWhr	320.0	229.9	90.0	
	6	100		250 MWhr	320.0	474.5	-154.5	
	6	100		1500 MWhr	320.0	1659.5	-1339.5	
	6	19		550 MWhr	109.1	794.5	-685.3	
	6	19		174 MWhr	109.1	368.6	-259.5	
Circuit Breaker Reclosing (2)	4	100		.5 MWhr	20.2	38.0	-17.7	

Table Notes:

(1) Costs based on EPRI SMES cost equation {Ref 10]. The EPRI cost equation is not accurate for SMES smaller than 1 MWhr.
(2) Benefit of Circuit Breaker Reclosing is based on $ 580,000 per event, assuming 2 events per year.
(3) Cases for industrial power back up from Ref 6 used a cost curve to calculate SMES for energy storage levels less than 20 MWhr.
(4) Cost estimates for SMES from Ref 7 used $ 250/MVA to calculate the cost for SMES.

4
COMPATIBILITY OF SMES WITH OTHER TECHNOLOGIES

Studies have shown that SMES and FACTS devices are compatible and have synergistic advantages. In their recent book "Understanding FACTS" [ref 19], authored by Narain G. Hingorani and Laszlo Gyugyi, they state that SMES has "the capability of controlling real as well as reactive power exchange with the AC system, and thus it can function as a static synchronous generator. The capability of controlling real as well as reactive power exchange is a significant feature that can be used effectively in applications requiring power oscillation damping, leveling power demand, and providing uninterrupted power for critical loads. This capability is unique to the switching converter type VAR [*volt-ampere reactive*] generator and it fundamentally distinguishes it from its conventional thyristor-controlled counterpart". In addition they state, "It is clear that STATCOM (or UPFC or other voltage source converters), in contrast to the SVC, can interface a suitable energy storage with the AC system for real power exchange. That is, the STATCOM is capable of drawing controlled real power from an energy source at its DC terminal and deliver it as AC power to the system. Thus, by equipping the STATCOM with an energy storage device of suitable capacity, extremely effective control strategies for the modulation of the reactive and real output power can be executed for the improvement of transient stability and the damping of power oscillation".

A SMES magnet output is DC voltage (see Figure 4-1, below) and requires a power converter to allow it to interface to a typical electric power transmission system. All of the currently marketed FACTS devices such as STATCOM and UPFC have a DC bus with a multi-pulse converter to interface to the electric transmission system. Technical studies have shown that a SMES magnet with a DC-DC chopper to regulate voltage can be directly interfaced with existing FACTS device designs. The voltage source inverter of a STATCOM or UPFC can easily be connected to the output of a SMES magnet chopper.

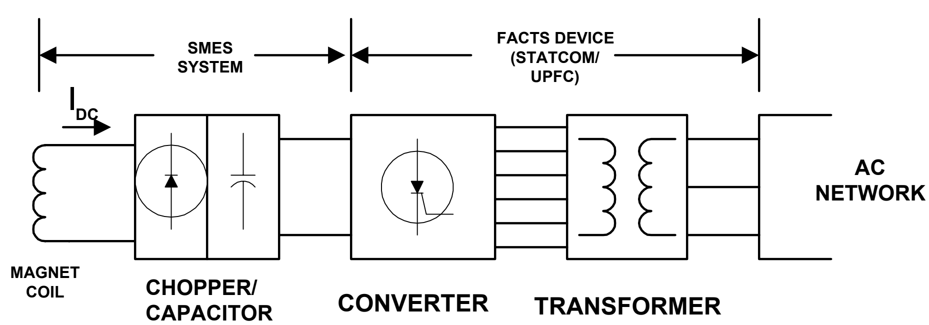

Figure 4-1
SMES System Components

The addition of SMES improves the performance of the FACTS device and allows injection of real power and the ability to withdraw real power from the system if necessary. This “full four quadrant” operation increases the flexibility of the overall FACTS device and its benefits.

Studies have also shown that the ability to inject real power can reduce the overall size (MVA) of the FACTS device saving additional costs. The study conducted by Battelle Northwest Labs for SDG&E simulating a SMES at the Blythe [Ref. 2] site indicated that a SMES would require a converter of about 50 MVA smaller than the equivalent STATCOM or SVC to achieve the same increase in system damping. In fact if the SMES is located near the generation source the advantage of real power injection to improve system damping is even more dramatic. Another study, investigating the benefits of SMES along the West Coast [Ref. 5], indicated that if SMES were located at the Palo Verde generating station instead, the rating of the SMES converter in relation to the comparable STATCOM or SVC could be reduced by 200 MVA yet would achieve the same increase in power transfer. Similarly the SMES benefits study on the New York State transmission system [Ref. 7] indicated that the SMES could be significantly reduced in size compared to the STATCOM alone if it were located near the Oswego generating complex. Table 4-1 shows a summary of the results of two of the studies and illustrates the benefits of SMES real power injection capability.

Table 4-1
Comparison of SMES/STACOM Ratings

Transmission Enhancement (MW)	SMES Power Rating (MVA)	STATCOM/SVC Power Rating (MVA)
500 [Ref 5]	250	450
400 [Ref 2]	300	350

When SMES is added to FACTS it increases the flexibility and the ability to be more effective as the transmission system changes. For example, if new generation is installed near a FACTS device adding SMES can make the FACTS device more effective for system damping as well as for all of the other benefits including, load leveling, spinning reserve, and the other benefits outlined in Table 2-1. The ability of SMES to easily “plug into” a FACTS device and the added functionality can significantly increase the value of SMES and FACTS both for utility applications.

The interface and control of the SMES magnet power charging (absorption of real power) and discharging (release of real power into the AC system) can be easily accomplished by controlling the DC link voltage on the capacitor. The chopper is designed to regulate the voltage across the capacitor so that there is a constant voltage provided to the converter. The chopper regulates voltage by regulating the duty cycle of the current that flows through the DC link capacitor. When the duty cycle is increased the DC link voltage drops and the magnet coil begins absorbing power, and vice versa when the magnet coil is releasing power. The converter controls the flow of active power by regulating the phase of the voltage relative to the voltage of the AC network bus. Advancing the phase delivers active power while retarding the phase absorbs active power. Figure 4-2 below shows a simplified block diagram of the control concept.

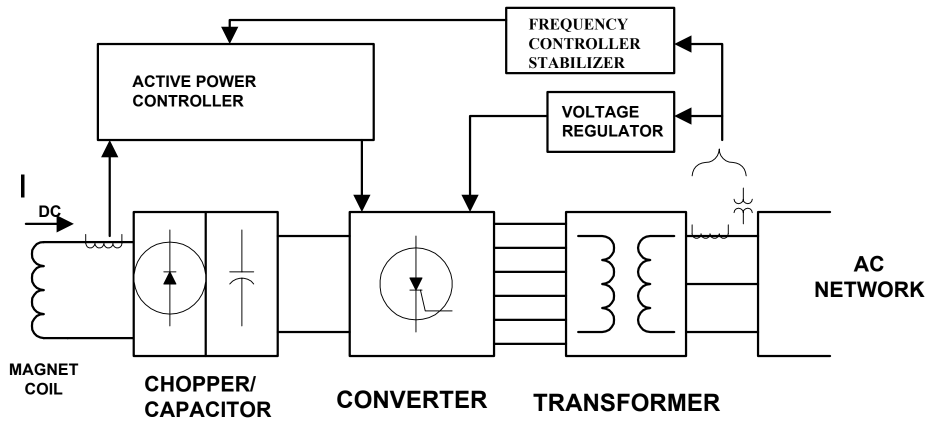

Figure 4-2
SMES-FACTS With Block Control Diagram

If a FACTS device has already been installed the addition of SMES to provide frequency control, backup power to large customers, power quality enhancement, spinning reserve, tie line control (AGC), or a number of other control function benefits, is a natural next step. The natural compatibility and the additional functionality benefits provided by SMES should be considered when designing a FACTS system.

Depending on the required energy storage capacity the addition of a magnet and chopper could be a small incremental cost as compared to the overall FACTS device, and it is possible that the overall FACTS device could be smaller in capacity (MVA) due to the performance benefits of injecting real power. Figure 4-3 shows the how the cost for the magnet system as a percentage of the total system cost drops off for situations where energy storage requirements are low and power output capacities are high, which is often the case for transmission enhancement applications. This chart is based on using cost estimates for the magnet system and Power Converter System (PCS) from the report "SMES: EPRI Cost Estimate" [Ref. 10] and its appendices that summarize SMES costs. The reference basis for estimating energy related and PCS costs is equation 4-3 of that report. This cost equation includes terms that account for nth-of-a-kind (NOAK) turnkey costs. This graph shows the percentage of the costs for the magnet system as compared to the total system costs, for four different PCS power ratings (50,150, 300, and 450 MW) and for energy storage ranging from 0.1 to 1650 MWhr. For applications that employ transmission enhancement by improving power system damping, such as in the SDG&E, West Coast Benefits Study, and SCE studies, the SMES energy and power are in the .1 MWhr, 450 MVA range, and the magnet system represents about 40% of the total cost. In this case if you were add the magnet system to an existing 450 MVA STATCOM it would be about 78% of the cost of the original STATCOM.

By adding the magnet system to the STATCOM the overall benefit/cost ratio improves dramatically.

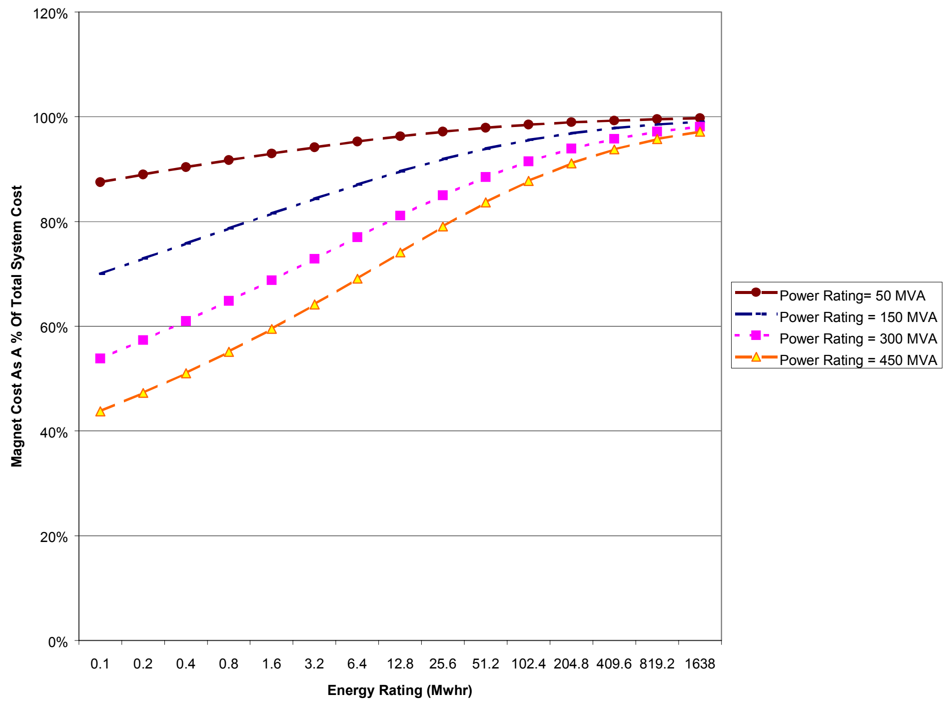

Figure 4-3
Cost of Magnet System As a Percent of The Total SMES/FACTS System Cost

5
SMES IN THE DEREGULATED UTILITY ENVIRONMENT

The Federal Energy Regulatory Commission (FERC) has been pursuing a philosophy of fostering a more competitive electricity market in the United States, starting with its first Notice of Public Rule Making in 1995 on creating open access the transmission system. Then, with FERC order 888, FERC required all electric utilities to file an open access tariff, essentially providing open transmission access to all private parties on an equal basis. More recently FERC has issued order 2000 which will require all public utilities that own, operate or control interstate electric transmission to file by October 15, 2000, a proposal for a Regional Transmission Organization (RTO), or, alternatively, a description of any efforts made by the utility to participate in an RTO. The formation of Regional Transmission Organizations (RTOs) must be operational by December 15, 2001.

The pace of competition in electric energy markets has intensified in recent years. To gain the full benefits of competition, market institutions will need to develop that allow transactions to take place fairly and efficiently. RTOs will be a major focus of the commission's electric markets work.

As part of the on-going electric industry restructuring effort, FERC issued Order 888 (Final Rule) on April 24, 1996. This Order formalized the Notice of Proposed Rulemaking (NOPR) about open access, which FERC issued on March 29, 1995. As FERC notes in the Final Rule summary, many utilities responded to open access and by the time the NOPR was issued, 38 utilities had already filed wholesale open access transmission tariffs with FERC. By the time the Final Rule was issued, 106 public utilities had filed open access tariffs. Through Order 888 and the NOPR, FERC was able to encourage more and more utilities to open their transmission systems and provide utilities with access to each others' transmission systems for wheeling power without undue discriminatory pricing, which results from transmission owning utilities exercising monopoly market power. Therefore, the thrust of FERC Order 888 was to promote wholesale competition through open access transmission and remedy undue discrimination in accessing monopoly owned transmission wires. The goal of FERC 888 was to bring more efficient, low-cost reliable power to the nation's electricity consumers.

In terms of low-cost power and related cost reductions, FERC stated in Order 888 that the nation would save a huge amount by implementing open access. This cost savings figure is a staggering sum of \$3.8 to \$5.4 billion dollars per year. The Commission said that consumers would save this amount because of increased competition among utilities and higher efficiencies resulting from open access and elimination of pancaked transmission rates.[1] Until now, the

[1] In wheeling from one system to another the rates of each system are added together to form a single rate that may be too expensive to economically wheel power from one system to another even though there is plenty of low cost generation and transmission capacity.

problem with competition has been the anti-competitive stance of some transmission owning utilities seeking to protect their own monopoly interests and insulate retail customers from the benefits of competition. However, as shown by the rapid rate at which utilities are responding with open access tariffs, there is a major push to open wholesale transmission markets and introduce more competition to realize open access benefits. It should be realized that FERC mandated that all transmission owners file an RTO plan. These benefits are similar to the benefits that have already been achieved in other deregulated industries such as the natural gas industry. By issuing the NOPR and Final Rule, FERC stimulated electric competition by making structural changes to level the playing field among vertically integrated utilities (VIUs) to further the goal of lowering costs to the nation's consumers without compromising the reliability of the nation's transmission system.

To make these structural changes, FERC Order 888 required VIUs to separate internal generation and transmission departments and their related functions. No longer could generation schedulers directly contact the same utility's transmission schedulers without following new scheduling protocols. In effect, the rules created a "Chinese wall" between the generation and transmission departments at utilities. In many instances, power schedulers and transmission schedulers were separated and placed in different secure facilities so the groups could not have direct physical contact. This was an approach to level the playing field among power marketers and utility power generators competing for the same transmission services. This change was made to prevent power schedulers from directly contacting their own transmission schedulers and having monopoly market power advantage over power schedulers from other utilities who would not have access to the same transmission information. FERC changed the rules so that the power schedulers from utilities or power marketing companies would have the same level of access to transmission services and information pursuant to the terms and conditions of the transmission provider's open access tariff.

FERC Order 888 requires each transmission service provider (utility) to file a transmission open access tariff for two types of transmission service. One type is postage stamp or load-based service, which enables the buyer to wheel across the provider's transmission system from various points of receipt and delivery. These points are specified in the tariff, and service is based on paying a pro rata share of the costs as a function of load. The other transmission service is point-to-point or MW-mile service based on contract rates between two specific points: the point of receipt and the point of delivery. The rates and available transmission capacity (ATC) for both types of service are identified and specified in the Open Access Same-time Information System (OASIS) electronic bulletin board maintained by transmission owning utilities.

The purpose of OASIS is to level the playing field by providing market information to market participants about available transmission capacity, transmission contracts, pricing and other factors. Market participants including power schedulers from utilities as well as power marketers have access to the same information via the Internet. Hence, OASIS is the communication tool for transmission schedulers to post market information about transmission services and for market participants to schedule transmission services in accordance with open access transmission tariffs. But open access and OASIS are only part of the solution to stimulate competition and prevent undue discriminatory access on the part of transmission owning utilities. Consequently, FERC issued Order 2000 to address remaining unsolved transmission issues involving more structural changes to transmission organizations.

Because of perceived continuing problems with limited competition and the need to address regional reliability issues in an era when deregulation began sweeping across the nation, FERC introduced Order 2000 and issued the Final Rule on December 20, 1999. This Rule introduced the characteristics and functions of new regional entities called Regional Transmission Organizations (RTOs). Previously, FERC Order 888 had encouraged the development of independent system operators (ISOs), but Order 2000 took the process one step further and subsequently encouraged voluntary development of RTOs across the nation. As part of the comprehensive open access plan, RTOs will ensure that the benefits of competition can be realized by public utilities and not thwarted by transmission owning utilities that have been able to fend off competition to protect corporate utility interests at the expense of their customers and ratepayers in some cases. By design, RTOs have to satisfy the requirements for the minimum characteristics and functions as identified by FERC. These include four characteristics and seven functions.

The four distinguishing characteristics of an RTO are:

1. Independence

2. Scope and Regional Configuration

3. Operational Authority

4. Short-term Reliability

Compared to existing ISOs, RTOs will have an expanded level of independence and influence in the sense that they will be “mini-FERCs” with jurisdiction over their own tariffs. The aim on the part of FERC is to push for more independent RTOs that will be responsible for handling regional issues that in the past would have been handled by FERC itself. Hence, appropriate scope and regional configuration play an important role in determining the scope and breadth of authority in dealing with regional transmission FERC related issues and devising workable solutions within acceptable timelines. In addition to the degree of independence from FERC, scope and regional configuration, RTOs will have operational authority over transmission systems and transmission control areas as ISOs do today. An RTO could in fact be comprised of many individual ISOs or Transco.[2] In the West, four RTOs have been proposed: RTO West, California RTO, Desert Star RTO and Rocky Mountain RTO. But because of difficult seams issues pertaining to transmission congestion contracts, firm transmission rights (FTRs), and different settlement requirements (10 minutes in California and longer than 10 minutes for BPA) there may be a push to have one RTO in the West, for example. Having a single RTO with policy setting responsibility to resolve seams issues (i.e. transmission interface ratings and controls) and set uniform tariffs, and a with an underlying layer of multiple ISOs and/or Transcos throughout the West may be one workable solution to the problem of unworkable seams issues. Of course, one of the most important concerns is short or near-term reliability especially in deregulated electricity markets with low operating reserve margins. This factor will continue to play a major role as it does today especially during peak load conditions.

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[2] A Transco can be either a for-profit or non-profit company owning a transmission system.

The seven minimum functions of an RTO are as follows below, and the list is certain to grow and expand once the RTOs become more of a reality and are put into place.

1. Tariff Administration and Design
2. Congestion Management
3. Parallel Path Flow
4. Ancillary Services
5. Open Access Same-time Information System (OASIS)
6. Market Monitoring
7. Planning and Expansion

Again, many of these functions are showing up as difficult seams issues between proposed RTOs. As a result there may be a push to have larger RTOs, both geographically and in terms of amount of load served, to manage these issues more effectively by setting uniform standards, tariffs and rates over a broader area to deal with expansive seams issues. However, there may be other better ideas that come out of the RTO proposals that take the industry in a different direction either in the West due to the "broken" wholesale market problems or in other parts of the country where the seams issues are not so pronounced.

Perspective of SMES Benefits in a Vertically Owned Utility

Traditional vertically owned utilities, those which own both generation and transmission facilities, are saddled with the need to minimize operating costs as well as to minimize potential stranded costs that may not be recoverable in a deregulated environment. The option of SMES to enhance transmission benefits is attractive and offers the potential to operate generating resources more efficiently through eliminating transmission constraints. The investment issue of SMES and FACTS and even new transmission is how the investor would receive a return is not clear since ultimate ownership of the transmission assets is not clear. Order 2000 is intended to bring some order to the process. By December 2001 FERC plans to approve RTO plans for each transmission owner. A key issue then will be whether the transmission owner can get anymore than the regulated rate of return on investment. FERC is also being petitioned to increase the ROI rate.

Investor Owned Utilities (IOUs) are in various stages of evolutionary development as a result of deregulation. Some utilities still own their own transmission, distribution and generation assets but may be in the process of divesting generation assets. Others have decided to keep their generation assets but may or may not be required to sell them if these utilities elect to join an ISO or RTO, or form their own entity. Others have already joined ISOs and are less vertically integrated because they have divested generating assets and have opted to become transmission and distribution (i.e., pipes and wires) delivery companies. Some are going one step further and are letting a new breed of energy service providers (ESPs) handle the retail customer relationships including mass billing, energy procurement and delivery through the native transmission and distribution company, which was once a IOU that performed all of these functions. Even in IOUs with transmission and generation or power supply functions, these companies have had to separate their transmission personnel from power supply personnel to comply with FERC rules pertaining to deregulation.

In some cases, deregulation has caused IOUs to focus on splitting into generation and transmission business units and made them consider spinning off or selling their Transmission Business Unit to an ISO or to form a Transco (transmission company). These IOUs and other companies are grappling with forming regulated and non-regulated business units to compete more effectively in the deregulated marketplace or strategically position themselves for a buy-out or merger, since utility mergers have been on the rise for the past 10-15 years. IOUs are facing tremendous regulatory pressure and risk. These factors weigh heavily on a IOU in a stranded cost paradigm and limit its ability to focus on cutting-edge SMES technology.

To capture all the benefits, SMES needs to be applied to major regional reliability problems that affect many utilities so SMES can be scaled to give the highest benefit/cost ratio and ROE. There are a limited number of these potential projects, and they are typically too big and risky for a single utility to undertake especially when many utilities are affected as shown by the technical studies and the IOUs are dealing with stranded cost issues in the evolving deregulated market changing from cost-based rates to market-based rates. It appears that SMES issues may loom too large for most IOUs to deal with given the state of the industry with buyouts, mergers, new unregulated companies, regulated utilities, and transmission and distribution functions being separated from generation due to deregulation.

For the most part, it appears that IOUs will continue to use conventional technology to expand and rebuild the transmission and distribution infrastructure. However, there are two notable exceptions. One is the increased use of large FACTS devices in limited applications at sites on both sides of the continental US. The other is the introduction and use of small SMES devices for temporary distribution voltage-level applications. Both of these examples are positive developments, but it is too soon to tell if IOUs will be in a better position to build large-scale SMES devices that can compete with traditional approaches to transmission planning/engineering expansion of existing systems. It should also be pointed out that in a market without deregulation these transmission-enhancing technologies would be much more broadly embraced as an alternative to new construction, which would remain severely limited by environmental concerns.

In one respect, a large RTO would be better suited to evaluate the costs and benefits for a potential SMES project. An RTO with sufficient technical expertise would be able to evaluate the technical and economic considerations of a potential SMES project that could solve regional import limitation problems, for example. The RTO would be able to capture the value of the many benefits that SMES has to offer in terms of damping, ancillary services, etc. Whereas, a IOU may have difficulty with the project economics if the IOU received some of the benefits. While other utilities shared the benefits but wouldn't participate in cost sharing. However is possible that the project could be proposed and bid as a reliability project through an RTO's Request for Bids (RFB) process as a solution to a regional reliability problem.

Typically, IOUs do not unbundle transmission products and services. ISOs have unbundled ancillary services into several products (e.g., voltage regulation, spinning reserve, 10-minute reserve, 30-minute reserve, 60-minute replacement reserve and black start capability) and developed markets and prices for these ancillary services. Consequently, some IOUs now buy and sell these ancillary services in the ISO's markets. However, the ISO is the entity that develops the markets and prices for new products and services. Someday, these services may include SMES benefits such as transmission stability dampening, transient voltage dip improvement, dynamic voltage stability, tie-line control, load leveling, etc. Alternatively, an RTO may have a regional transmission reliability problem, issue an RFB and evaluate the bids based on all of these technical factors and ascribe value to each significant factor so that SMES can be compared on a level playing field with conventional technology. It is unlikely that a single IOU could assign value to all of the SMES benefits for a project that solves regional reliability problems, especially if the host ISO or RTO has not expanded its market to include many of the benefits that SMES provides in addition to energy storage and ancillary services.

IOUs have limitations in terms of the introduction and proliferation of SMES technology. Deregulation has forced IOUs to restructure, merge and reposition themselves to compete in evolving electricity markets, which show tremendous volatility when compared to other commodity markets. This influence and the stranded cost risk may be responsible for making utilities stay away from cutting edge technology including capital-intensive large SMES devices. Stranded cost and performance-based ratemaking are important subjects for IOUs and tend to drive them to do more with less until reliability or safety problems begin to arise. SMES projects have to be evaluated differently than the traditional IOU approach as with an independent generator.

Perspective of SMES Benefits By A Regional Transmission Organization (RTO) Under FERC's Order 2000

The goal of FERC Order 2000 is to further open up the national transmission system to provide low-cost power to consumers. The transmission system needs to be opened up to accommodate new merchant plants, merchant transmission projects, Transco and utility projects. These projects are desperately needed around the country due to unacceptably low reserve margins that currently exist due to continued load growth and the lack of new generation and transmission projects by IOUs over the past decade because of regulatory rate recovery uncertainties associated with deregulation. With the accelerated pace of transmission and resource planning, new project activity and construction over broad regions of the country, it is more important now that RTOs be put into place to plan, operate and maintain reliable electric systems. FERC Order 2000 envisions these RTOs solving regional transmission problems such as potential limitations or contingencies in one US state that could affect large population centers in other states with cascading outages and blackouts due to voltage collapse. In other regions there are significant import limitations into particular states that affect several interconnected utility systems. One of the seven responsibilities of the RTO will be transmission planning. As such the role of the transmission owner will, in all likelihood, be subsumed in such maters as regional coordination and even infrastructure investment. In such instances, it may be that a FACTS device, SMES, or combination of the two is the best solution to increase imports and provide additional important system benefits. In this case, it may take the resources of an RTO, which is bigger than an individual utility, to study and demonstrate the benefits of these devices for solving regional problems and find ways to pay for cutting-edge technology such as SMES. SMES may prove to be economical and competitive with conventional technology when scaled to the appropriate size, which would typically be too large, expensive and risky for an individual utility to attempt to solve a regional problem with this new technology. The cost recovery paradigm for the emerging RTOs is likely to be significantly different than the stranded cost recovery paradigm of the IOUs in today's deregulated economy.

RTO's will be the primary institutions for dealing with market participants directly. It is intended that RTOs will be completely independent of owners of generation and will let all market participants become involved in the competitive market place. RTOs will control the operation of the transmission grid.

It is envisioned that most of the existing Independent System Operators (ISO) will become RTOs. RTOs will be open to proposals for enhancement of transmission performance by any private entity. The underlying utilities will continue to own and maintain the transmission system. However, the RTOs will in most cases provide an open auction for new required transmission line facilities or alternatives that could provide the needed transmission capacity. As such SMES could compete with new proposed transmission lines for supplying additional transmission capacity by enhancing existing capability. There are many varied potential benefits and those benefits need to be valued by a large regional organization. The SMES project has to be scaled properly to effectively compete with generation and transmission line. Hopefully, the emerging regional transmission organizations will be able to capture the value and benefit of SMES devices so that it can compete successfully for transmission driven reliability projects, which are becoming more important in many areas of the country.

Uncertainty of RTO Investments in SMES

The uncertainties of investing in SMES by an RTO include many factors at the present time. The volatility of the energy market at the present time is a major concern. Perhaps as RTOs are developed and become larger and incorporate a larger portion of the transmission system in the United States, volatility of the energy market will be less. Although the recent experience in California has indicated wild swings in energy prices, indicating a very volatile energy market. The key factor causing volatility of the energy market is the availability of resources within the electric system and the amount of demand. Though transmission constraints have also contributed to energy price disparity, as witnessed by the Path 15 transmission limitation on the 500 kV system in California this past year. The other uncertainty that RTOs would have regarding investment of SMES would be the collection of potential revenue that they would obtain for resolving the transmission constraints. A revenue collection mechanism needs to be developed by FERC to provide a clear path for return on the investment for resolving transmission constraints. It is possible that the Independent System Operator or the local or state regulatory agency that has jurisdiction could develop this mechanism. FERC and ISOs have developed some limited mechanisms for obtaining a return on investments for resolving transmission constraints. Such mechanisms include "ancillary services markets" and development of "firm transmission rates". Unfortunately the emphasis of the private sector investment in the energy market has been primarily on the resource side. There could be some regulatory outcomes that could encourage investment in resolving transmission constraints and projects like a SMES.

Regulatory Outcomes That Would Encourage Investment in SMES

There are various ways that FERC could encourage investment in resolving transmission constraints. One way would be to provide a guaranteed return on investment as opposed to relying on a market-based return. Another way would be to encourage the establishment of ancillary service markets that would include transmission enhancements as one of the market items. In some recent decisions FERC has provided incentives to utilities to resolve transmission constraints. In its May 16, 2001 Order Removing Obstacles, FERC allowed utilities to accelerate the development of transmission to connect generators and resolve transmission constraints. The incentives included an accelerated return on investment up to 3% over the current allowable return, and accelerated depreciation from 30 years up to 10 years. The combination of this increased return and the accelerated depreciation is a strong incentive for utilities to invest in resolving transmission constraints.

This recent FERC order was only applicable for projects that are completed by November of years 2001 and 2002. However, it is possible that FERC may consider establishment of future incentives for resolving transmission constraints in order to ensure the reliability and availability of transmission. FERC realizes that it is important to resolve transmission constraints in order to maintain a competitive resource market. It is clear that the transmission system and the generation system are tied together and without an unconstrained transmission system a competitive generating resource market cannot exist. Therefore, it is highly likely that FERC and other regulatory agencies will soon focus on providing incentives for investment in transmission enhancements. It is very possible that these investments could come from both utilities and the private sector. Recently in California several private investors have indicated an interest in investing in transmission projects, which resolve transmission constraints under the ISO tariff.

Assessment of Potential for New Transmission Infrastructure

As discussed in Chapter 3, previous studies identified various transmission constraints within the western and eastern United States. Western US constrained transmission paths included the AC Pacific Intertie, the Arizona to California transmission system and the New York system, both the northwestern and southeastern portions. It is recommended that as a result of this study that a future study should be done to examine the transmission constraints throughout the United States and identify locations where SMES/FACTS devices could be established to resolve transmission constraints. These projects should then be evaluated using a cost/benefit model similar to the discounted cash flow model used in this report. These projects could then be ranked and compared and evaluated for investment purposes. This information could also be provided to utilities, RTOs and FERC itself to help them understand where the transmission constraints are within the US and what infrastructure is required to resolve these transmission constraints. In many cases, a solid-state power electronic type device such as a FACTS, or even a project which has energy storage capacities like SMES, could be a more attractive way to resolve a transmission constraint and more profitable than conventional methods, such as building new transmission lines. These investments could have other side benefits including reducing the impact on the environment and offer more controllability over power flow and security of the transmission grid in general.

6
COST/BENEFIT ANALYSIS

SMES Costs

Most of the cost benefit studies that were reviewed developed an expected installed cost of the complete SMES unit. Significant technological improvements have been made in both the magnet systems and the power converter since those studies were performed, and therefore it is important to revisit the cost estimating of SMES.

Improvements in the converter costs have been in the power electronic switching devices. Higher voltage and current capability has been developed resulting in fewer switching devices. Gate Turn Off Thyristors (GTO) can now operate up to 12 kV and at ampere ratings of 3000 Amps. Insulated Gate Bi-polar Transistors (IGBT) packages have been designed for voltages up to 2 kV and ampere ratings up to 1500 Amps. Because IGBTs require much simpler gate drive systems to trigger the switching of power, this has also reduced cost and improved reliability.

New superconducting magnet systems for SMES have been developed which operate at a much higher voltage, up from 1 kV to 24 kV, which results in reduced ampacity requirements of the superconductor. Also, methods for pre-fabricating the magnets in the factory have resulted in reduced costs for SMES smaller than 1 MWhr in size.

Cost/Benefit Model

Previous economic analyses of SMES had been performed utilizing net present value or benefit/cost ratios of the various enhancements of transmission system performance. A slightly different approach was used in this analysis, wherein, the single enhancement of increased transmission capacity was evaluated on a discounted cash flow (DCF) basis, utilizing return-on-equity (ROE) as a decision measure. ROE is a measure most investors can appreciate, in that, it provides a relative measure of profitability without the need to compare it to other investment opportunities. Other transmission enhancements offered by SMES provided in Table 2-1 of Chapter 2 would be additions to the single attribute of increased transmission capacity.

In any DCF analysis, the major variables include: capital and operating costs, financing, project life and macroeconomic parameters, such as inflationary expectations.

The following example is based on a SMES with a stored energy rating of 133 kWhr and a power rating of 480 MW that results in 480 MW of increased transmission capacity. This size and transmission enhancement is based on both the “West Coast Benefit Study” [Ref 5], and the “San Diego Gas and Electric’s SMES Benefit Study” [Ref 3]. For this interim economic evaluation the following assumptions were used:

Capital Costs and Financial Structure

Base Year			**2000**
Construction Start Date (Mmm-yr)			**Jan-2000**
Construction Length (XX.xx years)			**2**
Construction Cost Centroid			**70%**
Construction Completion Date (month/year)			Dec-01

	Municipal Debt	Partnership Debt	
Cost of Funds	**6.0%**	**10.0%**	**Total**
Term (years)	**30**	**30**	**Leverage**
Percent of Project		**50%**	**50%**
Weighted Discount Rate			15.0%

Underlying Inflation Rate	**2.0%**
Hurdle Rate	**20%**
Project Life (yrs)	**30**
Transmission Enhancement (MWe)	**480**
Construction Costs for 480 MWe plant (2000K$)	**$58,500**
Installed Cost (2001K$)	$62,284

Salvage Value (2030K$)	
Depreciation (DDB,SOYD,SL)	**sl**
Marginal Tax Rate	**50%**

Operating Costs and Revenues

Operations & Maintenance Costs (2000K$/yr)	**$1,000**	
Price Differential Frequency	**20%**	

	Output (MWh/yr)
Electricity	840,960

			Real Esc Rate
Market Value (2000$)			
	Electric Price Difference	**$22 /MWh**	**1%**

Figure 6-1
Input data sheet for the discount cash flow model

The cost ($ 58.5 Million) for this size SMES was based on the updated cost recently received from a manufacturer of SMES. The operating cost of $ 1 Million/yr. is based on costs for a 1 MWhr plant identified in EPRI's SMES Plant Costs: EPRI Estimate [Ref 10].The benefit stream produced by SMES was assumed to result from its ability to equilibrate separate energy markets by removing transmission constraints which may have existed. At various times during any year, arbitrage possibilities exist on congested transmission paths. In those energy markets above the congested path, prices are lower due to an oversupply of power. For energy markets downstream of the congested path, prices are higher because of a shortage of power supply. This price differential and its frequency of occurrence were used as the primary determinants of value of transmission capacity enhancement. These determinants were perturbed through a range of reasonable values. The resulting ROE was then regressed against the price differential and frequency inputs.

Business Cases

Six business cases have been developed for study of potential benefits of a SMES for transmission enhancement benefits. The six cases were developed from the previous studies that were performed, and were selected to represent a variety in size (i.e. MW capacity) and energy storage (i.e. MWhr) as well as benefits. Each business case was modeled for 15 different sub-cases, each representing a different price differential across a constrained transmission path and a variation of price differential frequency. This resulted in a total of 90 sub-cases.

Using the model described above, runs were made with three different values for price differential frequency: 10%, 20% and 30%; and for five different price differentials: $ 10/MWhr, $ 20/MWhr, $ 25/MWhr, $ 30/MWhr, and $ 35/MWhr. The price differential percentage, as mentioned earlier represents the amount of time that the price differential exists across the constrained transmission path. For each run the Net Present Value (NPV), Return on Equity (ROE) and Break Even point (years) were calculated. The net present value is based on a 30-year project life. The breakeven value is the point where the project begins to have a net present value. Detailed results for all runs are summarized in Appendices A through D.

Explanation of Business Cases

As discussed previously, there are six business cases that have been developed for study of the potential benefits of SMES for transmission enhancement benefits. The six cases were developed from previous studies that had been developed as part of previous studies that had been performed by other utilities and other EPRI working groups. The intent of each of these business cases is to get a broad cross section of the possible benefits from SMES applications in utilities for transmission enhancement benefits. The objective was to look at all the studies that were performed previously as described in Table 3-9 of this report.

- **<u>Business Case No. 1</u>**

  Business Case No. 1 represents the 900 MVA capacity super conducting magnetic energy storage device with roughly 1 MWh energy storage capacity. This case was originally from the study done by San Diego Gas and Electric entitled, "Evaluation of Super Conducting Magnetic Energy Storage at Blythe Site" [Ref 2]. This study was performed in 1995, and this case represents a large SMES, which was evaluated for increasing the Arizona – California transmission capability. The study for this business case indicated that it could increase the transmission capacity by about 407 MW of capacity. This benefit was primarily derived from improving transient stability performance for the transmission system. This business case represents the high end of the scale as far as MVA capacity for a SMES device. However, it also represents a fairly large increase of power capacity as well as transmission capability. The cost of this device was approximately $ 86.8 Million dollars in year 2000 dollars. The estimated benefit was about $ 145 Million and a present worth of $ 58.3 Million in the original study that was performed in 1995.

- **Business Case No. 2**

  Business Case No. 2 represents a 500 MW capacity SMES with roughly 1 MWh of energy storage capacity. This business case also was developed in the original study performed by San Diego Gas and Electric for evaluation SMES at its Blythe site performed in 1995. In that study, the beneficial capacity or increased transmission capability was estimated to be 300 MW of transfer capability. The cost of the SMES was estimated to be $ 50.9 Million in year 2000 dollars. The estimated benefit was about $ 80.7 Million, and the net present worth over a 30 year life was $ 29.8 Million in the original study that was preformed back in 1995.

- **Business Case No. 3**

  Business Case No. 3 represents 480 MW of SMES power capacity, 133 kWh of energy storage capacity, and results in an increase transmission enhancement benefit of roughly 500 MW with. Estimated cost was $ 49.6 Million, the original estimated benefit was $ 80.5 Million in year 2000 dollars. The net present worth over a 30-year time frame was $ 30.9 Million in the original study. (This business case comes from the West Coast Utility Transmission Benefits of Super Conducting Magnetic Energy Storage Study conducted by EPRI in 1996.) This study looked at the transmission enhancement benefits both for the Arizona – California transmission path as well as the AC Pacific Intertie running from the northwest part of the United States into California.

- **Business Case No. 4**

  Business Case No. 4 was from the West Coast Study [Ref 5] and represents a 260 MW capacity SMES with roughly 300 MW of transmission enhancement benefit with an energy storage capacity of approximately 72 kWh. Total cost of this SMES was estimated to be $ 35.2 Million, estimated benefits $ 48.3 Million, and a net present worth over a 30-year time frame of $ 13.1 Million in year 2000 dollars.

- **Business Case No. 5**

  Business Case No. 5 also represents a case from the study “Evaluation of Superconducting Magnetic Energy Storage At Blythe” [Ref 2]. This case represents a 30 MW capacity SMES with, a 60 MW capacity increase in transmission enhancement was modeled for the discounted cash flow model based on projected benefits based on capacity of this SMES. It has roughly 5 MWh of energy storage, a total cost of $ 56.2 Million, a benefit of roughly $ 87.7 Million and a net present worth of $ 31.6 Million. Business case No. 5 is unique in that it was one of the cases that were taken from the tie-line control improvement capacity. Tie-line control improvement capacity is described earlier in Chapter 4, evaluated the benefit of using SMES to reduce the tie-line error. Interchanges of power capacity across transmission systems between control areas often result in control errors. The SMES would be used primarily to absorb and discharge energy to basically zero out the control error.

- **Business Case No. 6**

  Business Case No. 6 represents an approximation of the new SMES, which is being installed in Florida at the Center for Advanced Power Systems, otherwise known as CAPS, which is being sponsored by the U.S. Department of Energy. This project is primarily being designed to test the capability of SMES to resolve power quality peak shaving power factor correction and transmission support demonstrations. This SMES is being built by BWXT Technologies. This business case represents taking a small power rating SMES and using it to provide a moderate amount of transmission enhancement. The transmission benefit was approximated based on its size and possibility of where it might be located in the system. The estimated transmission capacity enhancement benefit is approximately 250 MW. This amount of transmission enhancement benefit is based on linear extrapolation of business cases #1, #2, #3, #4, and #5. Obviously, the transmission benefit is highly a function of where it would be located in the system. However, an approximation was made to get an evaluation of the potential benefit of this SMES device for transmission enhancement benefits on its own merits. Based on a proposal by BWXT Technologies to the Department of Energy for the current SMES which is under construction the following capacities apply: the SMES would have 96 MW of capacity and roughly 28 kWh of energy storage capacity. This equates to about 100 mega joules of energy storage capability. The cost of this project is roughly $ 20 Million, as provided by BWXT in their presentation to the EPRI SMES/FACTS Working Group Meeting in Columbus, Ohio on January 31, 2001.

Results of Business Cases

The following section provides a summary of the results of the economic analysis of each of the business cases. As described earlier, each of the business cases was evaluated looking at a range of price differentials across the constrained transmission interface path as well as how often the price would vary. How often a given value of energy price differential occurs is called the price differential frequency. The energy price differential was varied from $ 10/MWh to $ 30/MWh. The price differential frequency, that is how often the price would vary in this range, was varied from 10% all the way to 30%. This means that 10% of all the time the price differential would exist or otherwise would be zero, or up to 30% of the time the price differential would exist or be zero. These values, based on recent historical market conditions, are considered to be a very conservative estimate.

Summary of Business Case No. 1

As described previously, business case No. 1 was developed in the SDG&E sponsored study of SMES located at the Blythe site, which is in the eastern part of California along the Arizona – California transmission path. This business case represented a very large power capacity SMES rated at roughly 900 MW. This business case was interesting in that it showed an average return on equity of about 17% with a high net present value of roughly $ 41.9 Million over a 30-year life span. The break-even point was about 15 years or roughly half the estimated life of the project. Because of the high cost of this project, almost $ 90 Million and the high power capacity associated with it, both the return on equity and the break even point are longer then most of the other business cases. This business case is interesting with respect to the price differential frequency. As a price differential frequency dropped below 20%, the return on equity almost went to zero. The break-even point for the cost of this project went beyond the total life of the project, beyond 30 years. While this business case does provide a moderate return on equity, of approximately 17%, and although the break-even point is roughly half the life span of the project, that is 15 years, it does provide a high net present value of $ 41.9 Million. This is primarily because the project had the highest transmission enhancement value of 407 MW. Compared to the other business cases, this is one of the more risky business cases, other than business case No. 5.

Summary of Business Case No. 2

Business case No. 2 also came from the SDG&E study examining the benefits of installing a SMES at the Blythe site in southeastern California. However, this business case the power capacity of the SMES was 500 MW and the transmission enhancement benefit was 300 MW. Total cost in year 2000 dollars was $ 50.9 Million. As can be seen in Table 6-1, this project or business case had a much better return on equity then business case No. 1 with a return on equity of roughly 24% overall.

The break-even period was somewhat shorter, roughly 12 years. However, the net present value was $ 31 Million, somewhat lower than business case no. 1. This case is similar to business case No. 1 in that the return on equity went almost to zero when the price differential frequency, that is how often the price differential actually existed across the constrained transmission path. When the energy price differential frequency went below 10%, the return on equity went to zero and the break-even time frame for the project or business case went beyond the life span of the project of 30 years. Although, less risky then business case No. 1, this case also shows that if the investor was interested in a higher return on equity or a faster break-even period, say less then 5 years, then this project would not be the best performing business case.

Summary of Business Case No. 3

This business case represented a case from the West Coast Benefit Study conducted by EPRI in 1996. The power rating capacity of the SMES was 480 MW with an energy storage capacity of 0.133 MWh. From that study the transmission enhancement benefit was identified to be 500 MW. Primarily, along the Arizona – California transmission path, the estimated cost for this business case was approximately $ 50 Million. This business case was promising in that it showed an overall average return on equity of roughly 71% and a break-even point of less then 5 years. This business case also had the highest net present value of roughly $ 56 Million. Besides having the highest net present value of any of the six business cases, this business case also had the second highest overall average rate of return on the equity and the second shortest break-even point in terms of pay back time.

Summary of Business Case No. 4

Business case No. 4 also came from the West Coast Benefit Study conducted by EPRI in 1996. This business case represents a SMES rated at roughly 260 MW with a relatively small energy storage capacity of roughly 72 kWh. The estimated transmission enhancement capability, based on technical studies, was roughly 300 MWh of transmission enhancement based upon transient stability improvement of the AC Pacific Intertie. The overall cost for this business case was $ 35 Million. This business case also showed a fairly high average rate of return on equity of 46%, with a break-even or pay back period of time of approximately seven years and the overall net present value of this project was approximately $ 32 Million. This business case only showed very low or zero return on equity when the price differential frequency dropped below 10% and the price differential cost, that is the cost of energy differential across the constrained transmission path, was below $ 15/MWh.

Summary of Business Case No. 5

Business case No. 5 represents a study that was done as part of the SDG&E study evaluation of a SMES located at the Blythe site. However, this SMES was evaluated for merely eliminating the tie-line control error between control areas within the system. The benefit that was developed was based on a production cost model that was used in that study back in 1995. All the cost have been updated to year 2000 dollars. The power rating capacity of this SMES was roughly 30 MW and had an energy storage capacity of 5 MWh. This business case modeled a transmission enhancement benefit of approximately 60 MW of increased transmission. The overall cost, $ 56 Million, for this particular business case was relatively high because of the high-energy storage capacity required to maintain tie-line control error. The results of the economic analysis for this business case showed poor results. Almost in all cases regardless of price differential or price differential frequency, the return on equity was almost zero percent and in all cases showed a break-even point well beyond the 30-year expected life of the SMES. And in all cases showed a very low net present value, only when the price differential frequency went above 30% with a price differential cost of roughly $ 25-30/MWh across the constrained transmission path did it even show a positive net present value. Results of this business case indicate that the energy storage capacity must be below 1–2 MWh and the transmission enhancement must be above roughly 200-300 MW of capacity to result in an investment type business case scenario.

Summary of Business Case No. 6

Business case No. 6 represents the SMES that is proposed to be built and installed at the Center for Advanced Power Systems at Florida State University. This facility is also known as the National High Magnetic Field Laboratory that is currently sponsored by the Department of Energy. The purpose of this laboratory is to investigate the benefits of superconductivity and electromagnetic analysis design and experimentation. This facility has a dedicated 50 MW substation supplied by the local utility at 115 kV. The purpose of this experiment will be to not only investigate the benefits of SMES but also the possibility of investigating the concept of a super-conducting substation. The superconducting magnet as supplied by BWX Technologies will have a power rating capacity of 96 MW and overall energy storage capacity of roughly 28 kWh or equivalent of 100 mega joules. The total cost for this project is estimated to be approximately $ 20 Million.

The transmission enhancement benefit for this business case was based on an estimate of the size and power rating and energy storage capacity of this SMES. The transmission enhancement benefit was approximated to be 250 MW. This business case showed the highest return on equity of all the business cases at 149% overall average return on equity. However, it should be cautioned that one of the key elements in this evaluation was the transmission enhancement benefit. It is recommended that further studies be done simulating this size SMES at various locations within the US utility network to determine the potential transmission enhancement benefit for this SMES. A firm or committed evaluation of the transmission enhancement benefit and overall determination of this business case should be continued or evaluated. This business case had a very short break-even period; in fact, it had the shortest break even of any of the six business cases, approximately four and a half years, and a net present value of nearly $ 27 Million. The interesting thing about this business case is that it is based on recent cost estimates and is considered to be more accurate in terms of cost estimates. It is also based on a firm energy storage and power rating capacity. The results of this business case are very promising indeed.

One way to get an overall understanding of the results of this analysis is to average all of the results for each of the 15 sub-cases (representing variation in price differential and frequency – see previous discussion) for each business case. Table 6-1 provides a summary of the average.

Table 6-1
Summary of Economic Analysis of Business Cases (Year 2000$)
Each Case Represents the Average of 15 Sub-cases

Business Case	Power Capacity (MW)	Energy Storage (MWhr)	Transmission Enhancement (MW)	Cost ($ x Million)	Net Present Value ($ x Million)	Return on Equity (%)	Break Even (Yrs.)
1	900	1	407	$ 86.8	$ 41.9	17 %	15.2
2	500	1	300	$ 50.9	$ 31.1	24 %	11.7
3	480	0.133	500	$ 49.6	$ 56.6	71 %	4.7
4	260	0.072	300	$ 35.2	$ 32.3	46 %	6.7
5	30	5	60	$ 56.2	$ 1.6	0 %	53.1
6	96	0.028	250	$ 20.0	$ 27.1	149 %	4.5

Summary of All Business Cases Based on the Effect of Changing the Price Differential Frequency

The effect of the fluctuation of the energy prices across a constrained transmission path is often called the price differential frequency, which is how often the price actually fluctuates up and down. For example a worse case scenario would be that the price differential would only be $ 10/MWh across the transmission interface, which means the difference between the price on the sending and receiving ends is only $ 10/MWh. The worse case would be if the price differential frequency was only ten percent of the time, which would mean the price differential across the constrained transmission path was only $ 10/MWh and only occurred 10% of the time during the year. This is a very pessimistic or conservative estimate. On the other hand, the best case (used for this study) would be a price differential across the constrained transmission path of $ 30/MWh with the price differential occurring 30% of the year. Some would consider this to be optimistic, however, evaluation of the Arizona – California transmission path, based on ISO studies, indicated that actually the price differential can be much higher and the frequency of occurrence can be much higher then 30%. The results of these business cases that have been evaluated are considered to be on the conservative side. The following graphs represent a summary of all the business cases as a function of the price differential frequency. All of the cases that were evaluated or analyzed using the discounted cash flow model are provided in the appendixes.

Variation of Price Differential Frequency and the Effect on the Return on Equity

The following Figures 6-2, 6-3 and 6-4 represent the variation of energy price differential frequency from 10%, 20% to 30%. Each graph represents a variation of the energy price differential on the horizontal axis from $ 10/MWh up to $ 30/MWh, while the vertical axis shows the return on equity. Each line on each graph represents one of the six business cases. What is interesting about these graphs is they confirm the results of Table 6-1, which show an overall average of the results. These graphs show a trend upward to the right indicating, as you would expect, as the energy price differential increases the return on equity also increases. What is interesting about these graphs is that they also confirm that business case No. 6 has the highest return on equity in all cases for all price differential frequencies and for all energy price differentials. It also shows that business case no. 1 has the lowest overall return on equity and confirms that business case No. 5 is almost out of the picture completely as an investment scenario for all conditions.

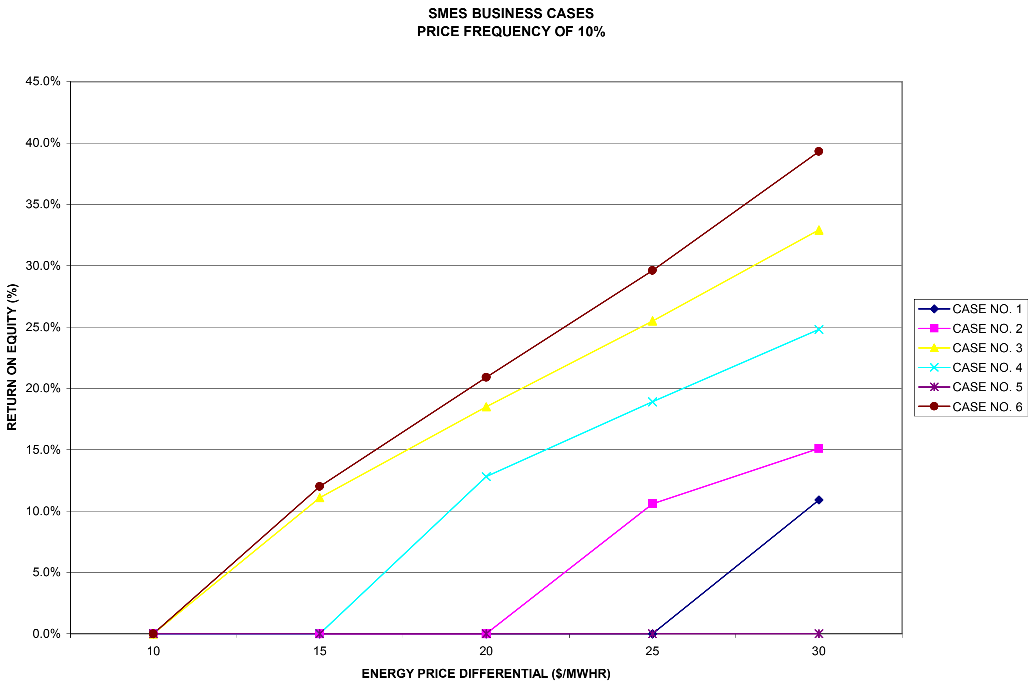

Figure 6-2
Return on Equity as a Function of Energy Price Differential with an Energy Price Differential Frequency of 10%

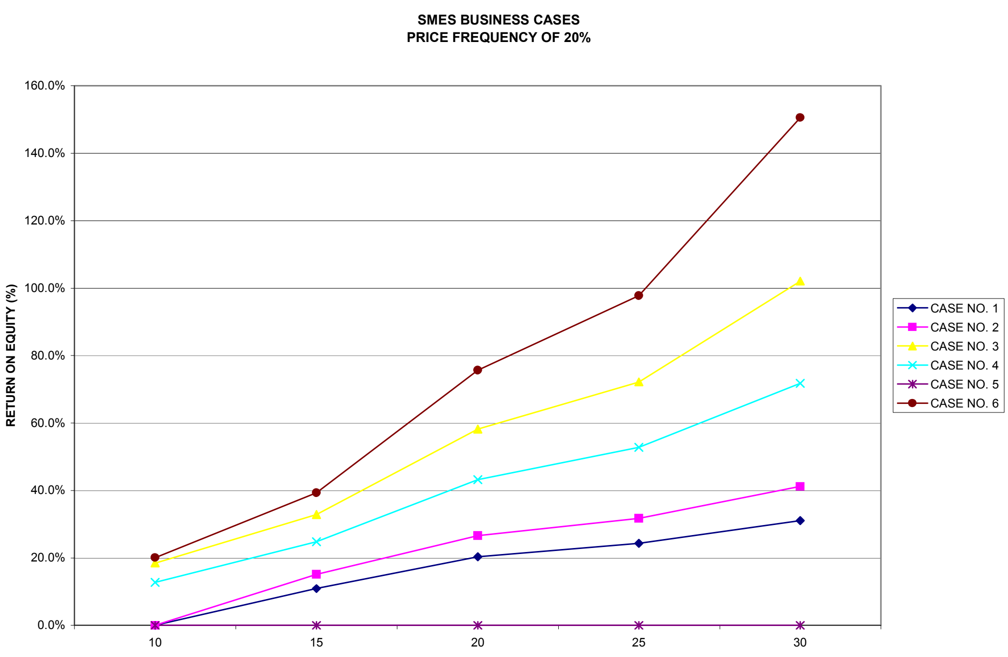

Figure 6-3
Return on Equity as a Function of Energy Price Differential with an Energy Price Differential Frequency of 20%

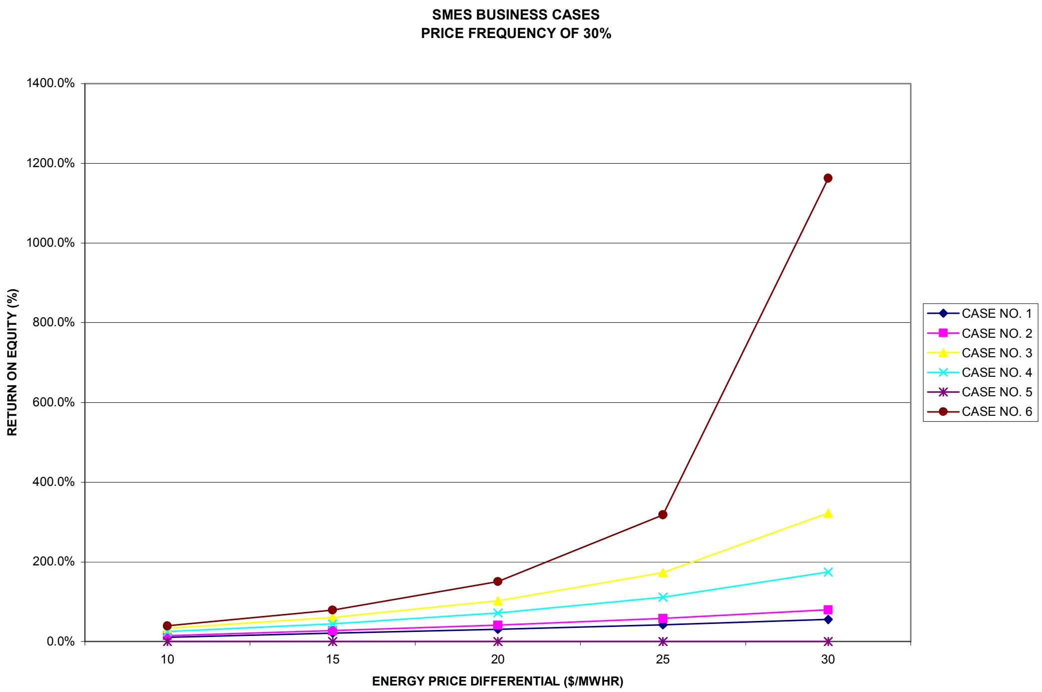

Figure 6-4
Return on Equity as a Function of Energy Price Differential with an Energy Price Differential Frequency of 30%

Variation of Price Differential Frequency in the Effect on Net Present Value

The following figures 6-5, 6-6 and 6-7 represent the variation in price differential frequency from 10%, 20% and 30%. Again, these graphs show a similar trend in that as the energy price differential increases the net present value also increases. However, these graphs show that the best net present value is represented in business case No. 3 as opposed to business case No. 6 in the previous discussion. These graphs indicate also that business case No. 6 has the lowest overall net present value. Again, business case No. 5 is almost completely out of the picture in terms of net present value as an investment scenario. When the price differential frequency is low and the energy price differential across the constrained transmission path is low, almost all of the business cases appear to be very close or very similar in terms of net present value between $ 5 Million to $ 10 Million in net present value for all three price differential frequency cases.

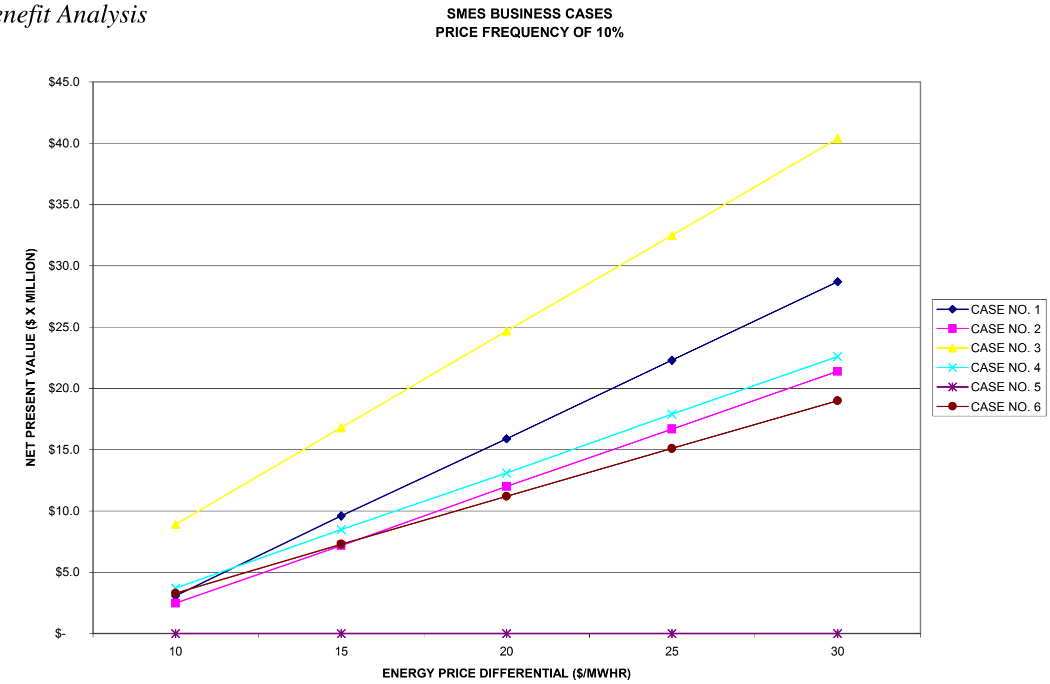

Figure 6-5
Net Present Value as a Function of Energy Price Differential with an Energy Price Differential Frequency of 10%

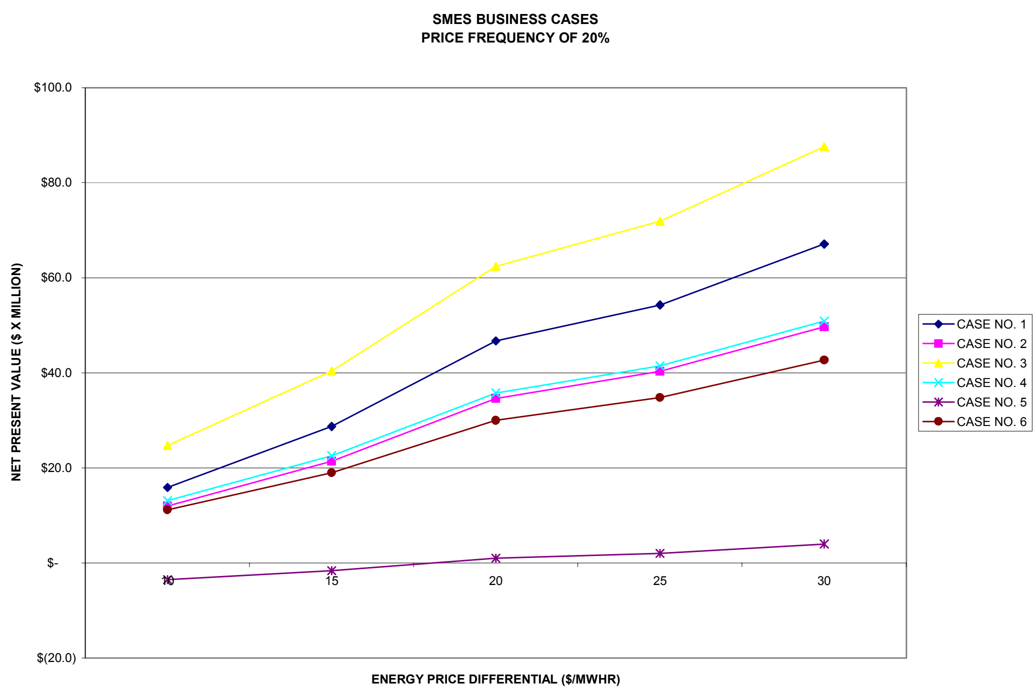

Figure 6-6
Net Present Value as a Function of Energy Price Differential with an Energy Price Differential Frequency of 20%

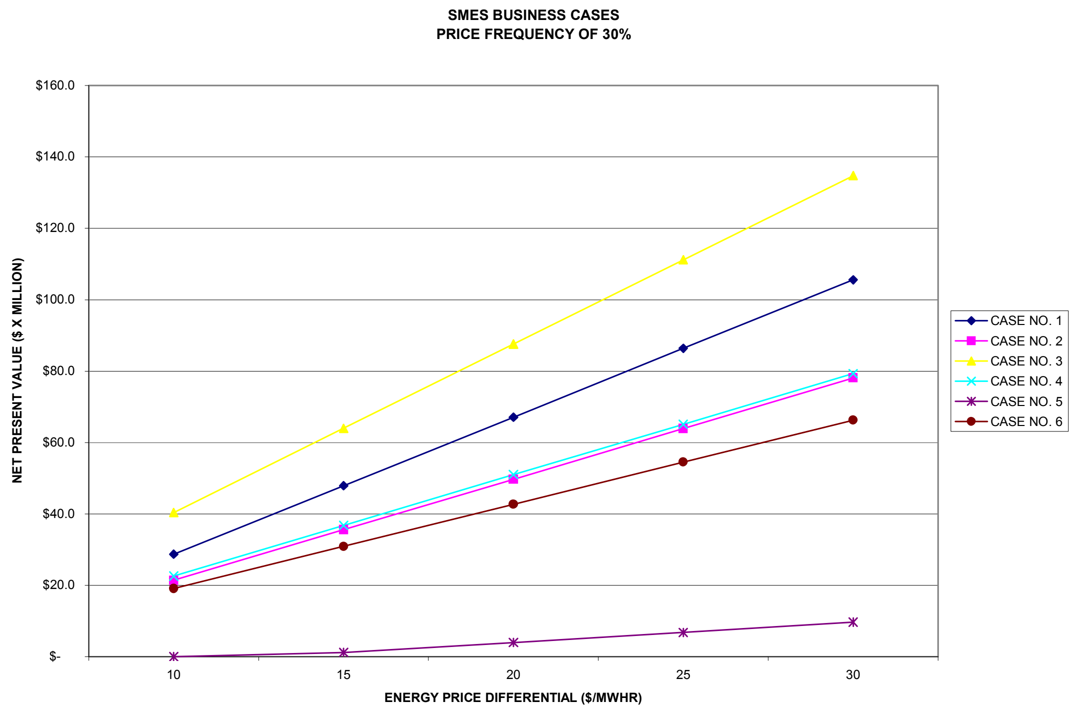

Figure 6-7
Net Present Value as a Function of Energy Price Differential with an Energy Price Differential Frequency of 30%

Variation of the Price Frequency Differential and the Effect on the Break-Even Point

Figures 6-8, 6-9 and 6-10 represent the variation of price differential frequency between 10%, 20% and 30% and the effect on the break-even point or payback period of the SMES project. The general trend, as one would expect, is that as the energy price differential increases the break even or pay back period becomes less and there is a downward and to the right trend on all these three graphs. The break-even analysis indicated something different then the rate of return on equity or the net present value in terms of which business cases are most promising. These three graphs actually show and confirm that business case No. 6 has the shortest payback period time for all energy price differentials and price differential frequencies. It also confirms as in the other analysis that business case No. 1 has the longest payback period or break-even point for all cases.

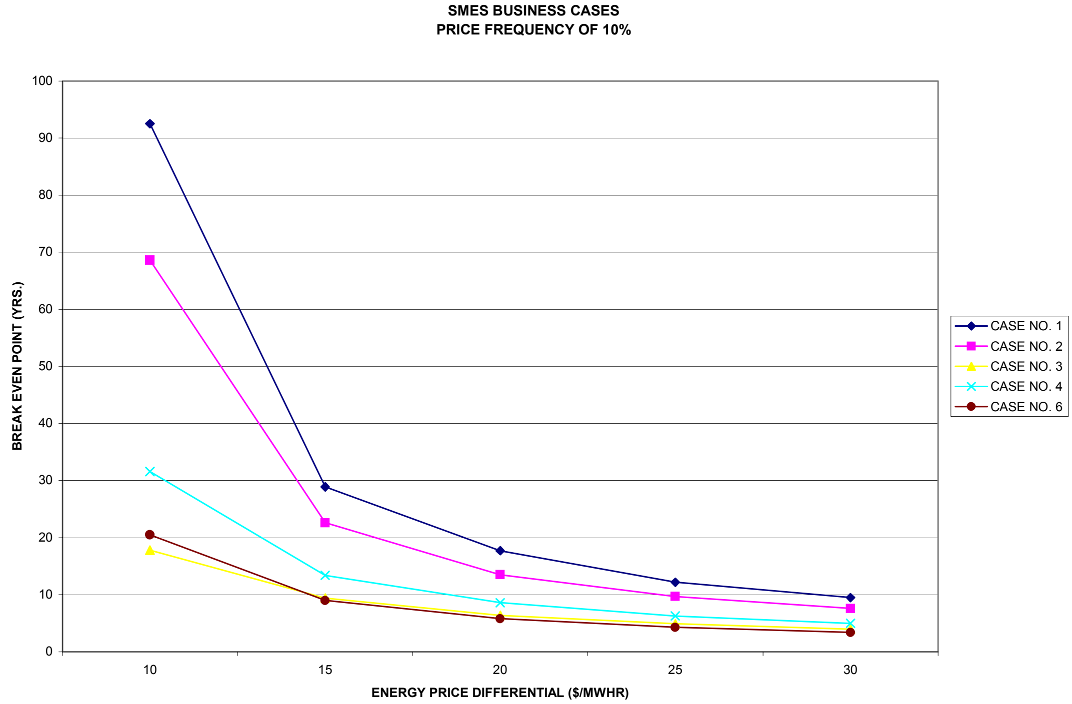

Figure 6-8
Break Even Point as a Function of Energy Price Differential with an Energy Price Differential Frequency of 10%

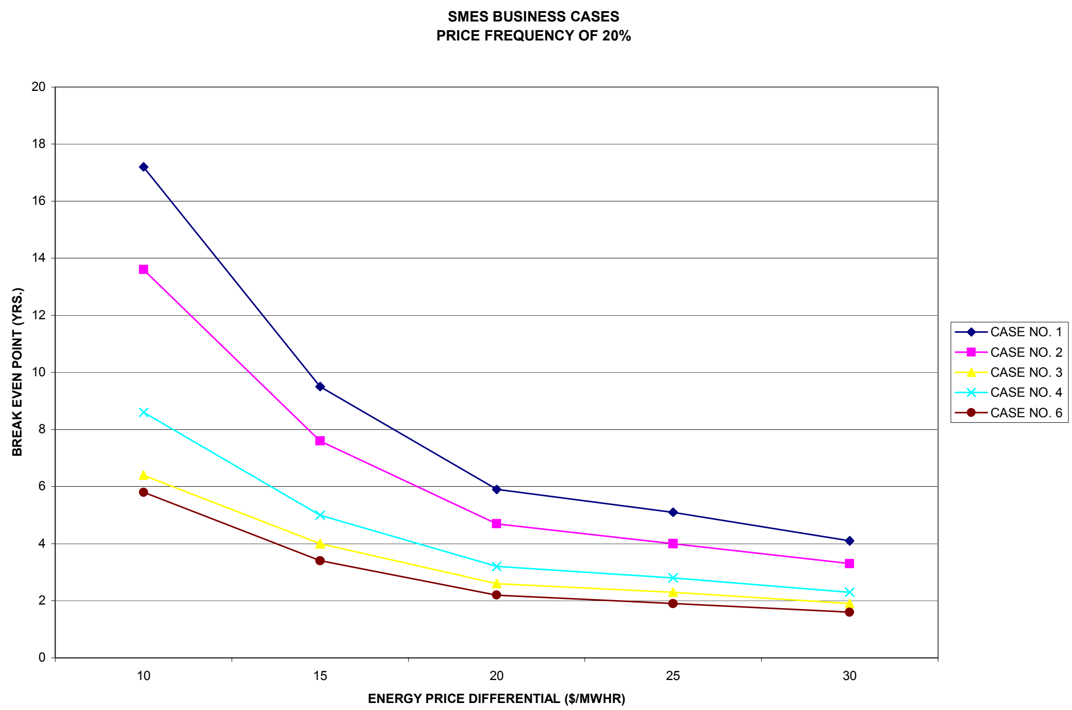

Figure 6-9
Break Even Point as a Function of Energy Price Differential with an Energy Price Differential Frequency of 20%

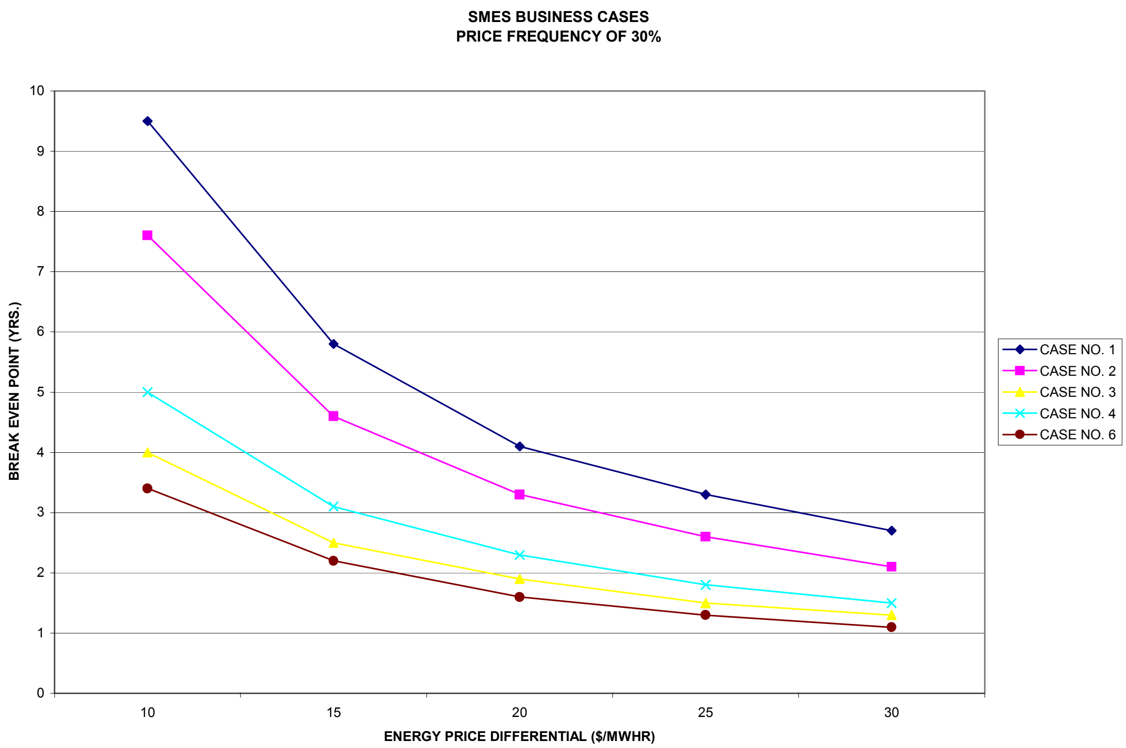

Figure 6-10
Break Even Point as a Function of Energy Price Differential with an Energy Price Differential Frequency of 30%

As expected the Rate of Return on Equity (ROE) and Net Present Value (NPV) both increase as the price differential ($/MWhr) is increased and the frequency of occurrence (%) of the price differential is increased. Also the break-even point decreases as the price differential ($/MWhr) is increased and the frequency of occurrence (%) of the price differential is increased.

It is interesting to note that the average price differential across the Arizona – California path during the last the period of May – October of year 2000 has been well over $ 30/ MWhr. This is the same constraining transmission path that was modeled in the studies that had identified the increased transmission enhancement of 500 MW modeled in this example. This same type of analysis can be used for any size power rating and energy rating SMES.

Explanation of Discounted Cash Flow Model

The Discounted Cash Flow (DCF) model used in this study is the same model used for evaluation of generating resource project viability by investors. The DCF is commonly used to evaluate, for investment purposes, the benefits of investing in generating resource projects. This model has been adapted to model the benefits due to transmission enhancements. The advantage of the discounted cash flow model is that given a cost of capital it will give the return on equity. Unlike conventional net present value analysis, which does the reverse, it gives the net present value (NPV) based on a given return of equity. The advantage of the discounted cash flow is that it gives the investor a return on equity or a value that they can use for determining whether an investment is viable or profitable.

This discounted cash flow model calculates net present value, return on equity and break-even point. These values are important to the investor since they determine how much money is going to made over the entire investment of the project (i.e., net present value), the annual return on the investment (i.e., return on equity), and how long it would take for the project to break even (i.e., break-even point). The basic concept behind the discounted cash flow is the cost of money and what money is worth in today's terms. For example, a sum of money today is worth more then the same sum at a future date. The reason for this is that one can invest the sum today and receive a larger amount in the future. The present value of a future sum is its value today. To determine the present value of future cash flows, one must discount them. The discounted cash flow model, or DCF, uses a rate that applies to the project this rate is often called the discount rate. This discount rate includes many factors, including the tax-adjusted weighted-average cost of capital.

Various inputs are required for this discounted cash flow model. The inputs are as follow:

- Base year
- Construction start date
- Construction time length
- Life of project
- Inflation rate
- Construction cost
- Salvage value
- Depreciation rate
- Operation of maintenance cost
- Price differential frequency
- Energy price differential

The base year construction time date was assumed to be year 2000. The construction time for a project described in this report is assumed to be two years and was modeled in the discounted cash flow analysis. The life of the project was assumed to be 30 years. The inflation rate was assumed to be 2%. The construction cost was determined based on the results of the studies that were done previously, as summarized and described in Table 10 of this report. The salvage value was not modeled in this discounted cash flow model; the depreciation model used was a straight-line depreciation. The operation maintenance cost was assumed to be approximately $1,000,000 per year. The price differential frequency and energy price differential was varied as described previously in the sensitivity analysis.

In summary, the discounted cash flow model is considered to be an accurate way to model a construction project and determine whether it has high profitability and how good its investment grade would be. The DCF model evaluates the cost of money over time and provides an accurate time proven method of evaluating the profitability of projects similar to this one described in this report.

7 CONCLUSIONS AND RECOMMENDATIONS

A review of previous studies that evaluated potential benefits of Superconducting Magnetic Energy Storage (SMES) connected to utility systems was conducted. Results indicated that applications for increasing transmission transfer capacity through system stabilization and voltage support provided the most benefits. Nine previous studies were reviewed; approximately 23 different scenarios for various applications of SMES were simulated in these studies. Of these 23 cases, 8 cases showed positive net present value over the expected life of the SMES unit.

Interviews were conducted with investigators of the previous studies to determine why the proposed SMES were never installed and to determine what would have to change to make it more SMES investment more likely. The main reason sited for not investing in SMES was the uncertainty of the outcome of impending deregulation and recouping revenues in rates or another mechanism. However, if energy prices and the energy price differential across constrained transmission paths between energy markets increased and became significant, then investment in SMES could become very attractive.

The potential benefits of combining SMES with FACTS devices were investigated. Results indicate that the overall size and cost of the SMES-FACTS combined device could be reduced resulting in a more efficient and versatile system for improving transmission system performance.

An investigation of the proposed FERC regulations and deregulated utility environment was conducted. Results indicate that through the development of Regional Transmission Operators (RTOs) the possibility of investment in SMES and similar devices to enhance transmission systems is more likely due to the benefits of pooled resources.

Six different business cases were evaluated, 5 of which were taken from the previous studies that were performed, and 1 represented the proposed SMES for the CAPS project in Florida. These business cases evaluated the benefits of SMES in a deregulated environment where energy prices can fluctuate across constrained transmission paths. In a deregulated environment the benefits of resolving a constrained transmission paths would be realized through Firm Transmission Service (FTS), Transmission Congestion Contracts (TCC) or through other mechanisms developed by the ISO or RTO to capture the energy price differential benefits. The energy price differential across a constrained path was simulated and varied to evaluate the sensitivity of the investment. The frequency of occurrence was also varied to determine investment sensitivity. Results indicated that all 6 cases produced a average positive net present value. Five of the business cases produced a rate of return on equity greater than 17%. However, only two of the business cases had a breakeven on investment of less than 5 years.

Recommendations

- It is recommended that as a result of this study that a future study should be done to examine the transmission constraints throughout the United States and identify locations where SMES/FACTS devices could be established to resolve transmission constraints. These projects should then be evaluated using a cost/benefit model similar to the discounted cash flow model used in this report. These projects could then be ranked and compared and evaluated for investment purposes. This information could also be provided to utilities, RTOs and FERC itself to help them understand where the transmission constraints are within the US and what infrastructure is required to resolve these transmission constraints.
- It is recommended that further studies be done simulating this size SMES at various locations within the US utility network to determine the potential transmission enhancement benefit for this SMES

8
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9

GLOSSARY OF ACRONYMS

BES – Battery Energy Storage

CAPS – Center for Advanced Power Systems

FACTS – Flexible AC Transmission Systems

FERC – Federal Energy Regulatory Commission

IOU – Investor Owned Utility

ISO – Independent System Operator

OASIS – Open Access Same Time Information System

PSS – Power System Stabilizer

RTO – Regional Transmission Operator

SMES – Superconducting Magnetic Energy Storage

STATCOM – Static Compensator

SVC – Static VAR Compensator

TCSC – Thyristor Controlled Series Capacitor

UPFC – Unified Power Flow Controller

VAR – Volt Ampere Reactive

VIU – Vertically Integrated Utility

A
SUMMARY OF BUSINESS CASES

Table A-1
SMES Business Cases - Average of Business Case 1

Case	Power Capacity	Energy Storage	Transmission Enhancement	Cost	Net Present Value	Return on Equity	Break Even	Price Differential	Price Diff. Freq.
#	(MW)	(MWhr)	(MW)	($xMillion)	($xMillion)	%	(YRS.)	($/MWh)	%
1	900	1	407	$86.8	$28.7	10.9%	9.5	10	30%
1	900	1	407	$86.8	$47.9	21.1%	5.8	15	30%
1	900	1	407	$86.8	$67.1	31.1%	4.1	20	30%
1	900	1	407	$86.8	$86.4	42.4%	3.3	25	30%
1	900	1	407	$86.8	$105.6	55.6%	2.7	30	30%
1	900	1	407	$86.8	$15.9	0.0%	17.2	10	20%
1	900	1	407	$86.8	$28.7	10.9%	9.5	15	20%
1	900	1	407	$86.8	$46.7	20.4%	5.9	20	20%
1	900	1	407	$86.8	$54.3	24.3%	5.1	25	20%
1	900	1	407	$86.8	$67.1	31.1%	4.1	30	20%
1	900	1	407	$86.8	$3.1	0.0%	92.5	10	10%
1	900	1	407	$86.8	$9.6	0.0%	28.9	15	10%
1	900	1	407	$86.8	$15.9	0.0%	17.7	20	10%
1	900	1	407	$86.8	$22.3	0.0%	12.2	25	10%
1	900	1	407	$86.8	$28.7	10.9%	9.5	30	10%
				Average	$41.9	17%	15.2		

Table A-2
SMES Business Cases - Average of Business Case 2

Case #	Power Capacity (MW)	Energy Storage (MWhr)	Transmission Enhancement (MW)	Cost ($xMillion)	Net Present Value ($xMillion)	Return on Equity %	Break Even (YRS.)	Price Differential ($/MWh)	Price Diff. Freq. %
2	500	1	300	$50.9	$2.5	0.0%	68.6	10	10%
2	500	1	300	$50.9	$7.2	0.0%	22.6	15	10%
2	500	1	300	$50.9	$12.0	0.0%	13.5	20	10%
2	500	1	300	$50.9	$16.7	10.6%	9.7	25	10%
2	500	1	300	$50.9	$21.4	15.1%	7.6	30	10%
2	500	1	300	$50.9	$12.0	0.0%	13.6	10	20%
2	500	1	300	$50.9	$21.4	15.1%	7.6	15	20%
2	500	1	300	$50.9	$34.6	26.6%	4.7	20	20%
2	500	1	300	$50.9	$40.3	31.8%	4	25	20%
2	500	1	300	$50.9	$49.7	41.2%	3.3	30	20%
2	500	1	300	$50.9	$21.4	15.1%	7.6	10	30%
2	500	1	300	$50.9	$35.6	27.5%	4.6	15	30%
2	500	1	300	$50.9	$49.7	41.2%	3.3	20	30%
2	500	1	300	$50.9	$63.9	58.0%	2.6	25	30%
2	500	1	300	$50.9	$78.1	79.3%	2.1	30	30%
				Average	$31.1	24%	11.7		

Table A-3
SMES Business Cases - Average of Business Case 3

Case #	Power Capacity (MW)	Energy Storage (MWhr)	Transmission Enhancement (MW)	Cost ($xMillion)	Net Present Value ($xMillion)	Return on Equity %	Break Even (YRS.)	Price Differential ($/MWh)	Price Diff. Freq. %
3	480	0.133	500	$49.6	$8.9	0.0%	17.8	10	10%
3	480	0.133	500	$49.6	$16.8	11.1%	9.4	15	10%
3	480	0.133	500	$49.6	$24.7	18.5%	6.4	20	10%
3	480	0.133	500	$49.6	$32.5	25.5%	4.9	25	10%
3	480	0.133	500	$49.6	$40.4	32.9%	4	30	10%
3	480	0.133	500	$49.6	$24.7	18.5%	6.4	10	20%
3	480	0.133	500	$49.6	$40.4	32.9%	4	15	20%
3	480	0.133	500	$49.6	$62.4	58.2%	2.6	20	20%
3	480	0.133	500	$49.6	$71.9	72.2%	2.3	25	20%
3	480	0.133	500	$49.6	$87.6	102.1%	1.9	30	20%
3	480	0.133	500	$49.6	$40.4	32.9%	4	10	30%
3	480	0.133	500	$49.6	$64.0	60.4%	2.5	15	30%
3	480	0.133	500	$49.6	$87.6	102.1%	1.9	20	30%
3	480	0.133	500	$49.6	$111.2	173.3%	1.5	25	30%
3	480	0.133	500	$49.6	$134.8	322.2%	1.3	30	30%
				Average	$56.6	71%	4.7		

Table A-4
SMES Business Cases - Average of Business Case 4

Case	Power Capacity	Energy Storage	Transmission Enhancement	Cost	Net Present Value	Return on Equity	Break Even	Price Differential	Price Diff. Freq.
#	(MW)	(MWhr)	(MW)	($xMillion)	($xMillion)	%	(YRS.)	($/MWh)	%
4	260	0.072	300	$35.2	$3.7	0.0%	31.6	10	10%
4	260	0.072	300	$35.2	$8.5	0.0%	13.4	15	10%
4	260	0.072	300	$35.2	$13.1	12.8%	8.6	20	10%
4	260	0.072	300	$35.2	$17.9	18.9%	6.3	25	10%
4	260	0.072	300	$35.2	$22.6	24.8%	5	30	10%
4	260	0.072	300	$35.2	$13.1	12.8%	8.6	10	20%
4	260	0.072	300	$35.2	$22.6	24.8%	5	15	20%
4	260	0.072	300	$35.2	$35.8	43.2%	3.2	20	20%
4	260	0.072	300	$35.2	$41.5	52.8%	2.8	25	20%
4	260	0.072	300	$35.2	$50.9	71.8%	2.3	30	20%
4	260	0.072	300	$35.2	$22.6	24.8%	5	10	30%
4	260	0.072	300	$35.2	$36.8	44.8%	3.1	15	30%
4	260	0.072	300	$35.2	$51.0	71.8%	2.3	20	30%
4	260	0.072	300	$35.2	$65.1	111.3%	1.8	25	30%
4	260	0.072	300	$35.2	$79.3	174.6%	1.5	30	30%
				Average	$32.3	46%	6.7		

Table A-5
SMES Business Cases - Average of Business Case 5

Case	Power Capacity	Energy Storage	Transmission Enhancement	Cost	Net Present Value	Return on Equity	Break Even	Price Differential	Price Diff. Freq.
#	(MW)	(MWhr)	(MW)	($xMillion)	($xMillion)	%	(YRS.)	($/MWh)	%
5	30	5	60	$56.2	x	x	x	10	10%
5	30	5	60	$56.2	x	x	x	15	10%
5	30	5	60	$56.2	x	x	x	20	10%
5	30	5	60	$56.2	x	x	x	25	10%
5	30	5	60	$56.2	x	x	x	30	10%
5	30	5	60	$56.2	$(3.5)	0.0%	45	10	20%
5	30	5	60	$56.2	$(1.6)	0.0%	90	15	20%
5	30	5	60	$56.2	$1.0	0.0%	240	20	20%
5	30	5	60	$56.2	$2.0	0.0%	93	25	20%
5	30	5	60	$56.2	$4.0	0.0%	46.4	30	20%
5	30	5	60	$56.2	x	x	x	10	30%
5	30	5	60	$56.2	$1.2	0.0%	190.1	15	30%
5	30	5	60	$56.2	$4.0	0.0%	46.4	20	30%
5	30	5	60	$56.2	$6.8	0.0%	26.5	25	30%
5	30	5	60	$56.2	$9.7	0.0%	18.6	30	30%
				Average	$1.6	0%	53.1		

Table A-6
SMES Business Cases - Average of Business Case 6

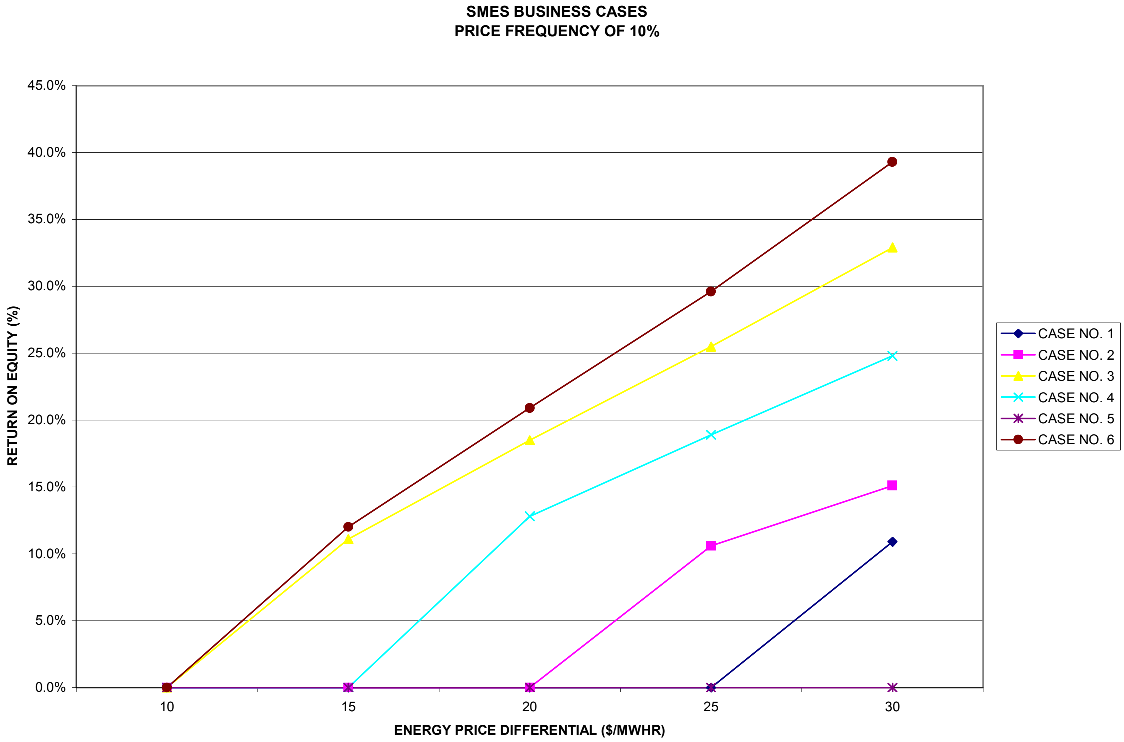
Case	Power Capacity	Energy Storage	Transmission Enhancement	Cost	Net Present Value	Return on Equity	Break Even	Price Differential	Price Diff. Freq.
#	(MW)	(MWhr)	(MW)	($xMillion)	($xMillion)	%	(YRS.)	($/MWh)	%
6	96	0.028	250	$20.0	$3.3	0.0%	20.5	10	10%
6	96	0.028	250	$20.0	$7.3	12.0%	9	15	10%
6	96	0.028	250	$20.0	$11.2	20.9%	5.8	20	10%
6	96	0.028	250	$20.0	$15.1	29.6%	4.3	25	10%
6	96	0.028	250	$20.0	$19.0	39.3%	3.4	30	10%
6	96	0.028	250	$20.0	$11.2	20.1%	5.8	10	20%
6	96	0.028	250	$20.0	$19.0	39.3%	3.4	15	20%
6	96	0.028	250	$20.0	$30.0	75.7%	2.2	20	20%
6	96	0.028	250	$20.0	$34.8	97.8%	1.9	25	20%
6	96	0.028	250	$20.0	$42.7	150.6%	1.6	30	20%
6	96	0.028	250	$20.0	$19.1	39.3%	3.4	10	30%
6	96	0.028	250	$20.0	$30.9	79.0%	2.2	15	30%
6	96	0.028	250	$20.0	$42.7	150.6%	1.6	20	30%
6	96	0.028	250	$20.0	$54.5	318.1%	1.3	25	30%
6	96	0.028	250	$20.0	$66.3	1162.3%	1.1	30	30%
				Average	$27.1	149%	4.5		

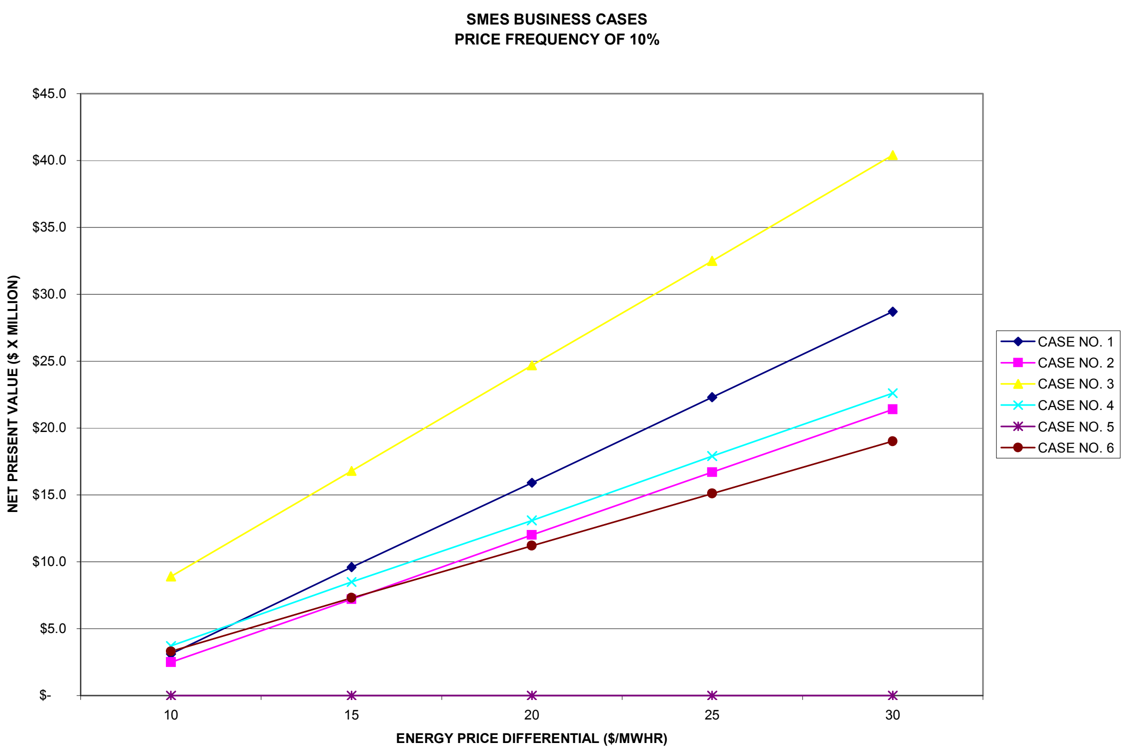
B
SMES BUSINESS CASES – PRICE DIFFERENTIAL FREQUENCY OF 10%

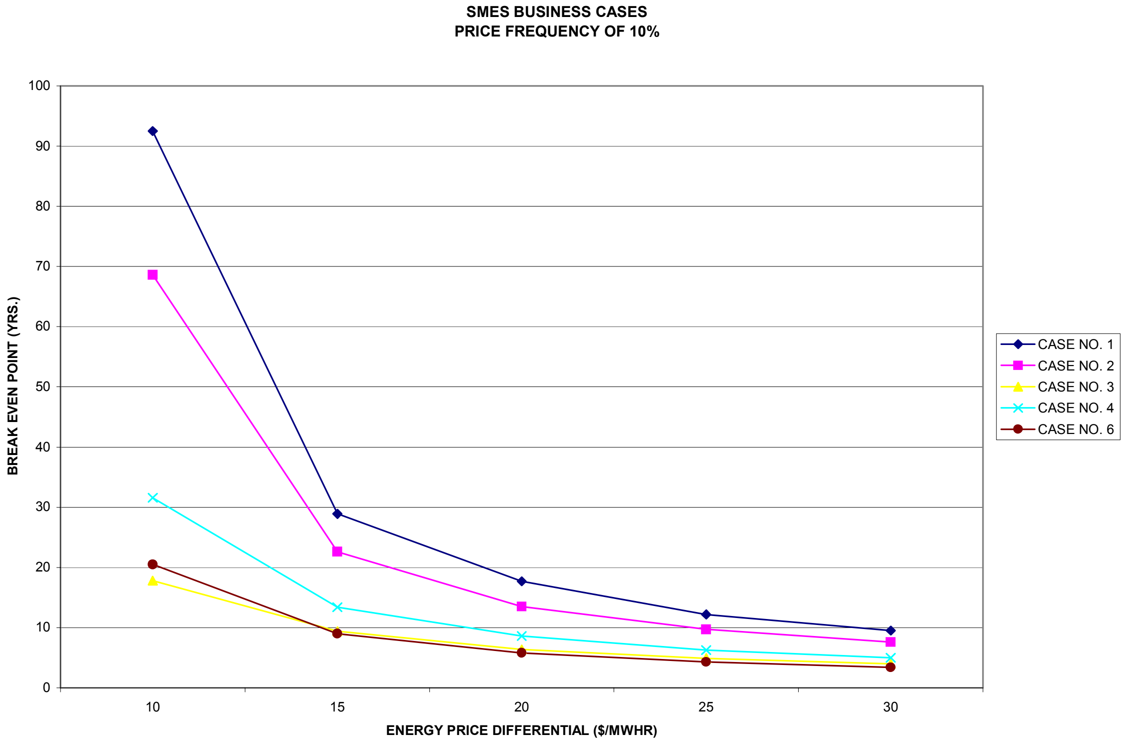
Table B-1
SMES Business Cases - 10% Price Differential Frequency

Case #	Power Capacity (MW)	Energy Storage (MWhr)	Transmission Enhancement (MW)	Cost ($xMillion)	Net Present Value ($xMillion)	Return on Equity %	Break Even (YRS.)	Price Differential ($/MWh)	Price Diff. Freq. %
1	900	1	407	$86.8	$3.1	0.0%	92.5	10	10%
1	900	1	407	$86.8	$9.6	0.0%	28.9	15	10%
1	900	1	407	$86.8	$15.9	0.0%	17.7	20	10%
1	900	1	407	$86.8	$22.3	0.0%	12.2	25	10%
1	900	1	407	$86.8	$28.7	10.9%	9.5	30	10%
2	500	1	300	$50.9	$2.5	0.0%	68.6	10	10%
2	500	1	300	$50.9	$7.2	0.0%	22.6	15	10%
2	500	1	300	$50.9	$12.0	0.0%	13.5	20	10%
2	500	1	300	$50.9	$16.7	10.6%	9.7	25	10%
2	500	1	300	$50.9	$21.4	15.1%	7.6	30	10%
3	480	0.133	500	$49.6	$8.9	0.0%	17.8	10	10%
3	480	0.133	500	$49.6	$16.8	11.1%	9.4	15	10%
3	480	0.133	500	$49.6	$24.7	18.5%	6.4	20	10%
3	480	0.133	500	$49.6	$32.5	25.5%	4.9	25	10%
3	480	0.133	500	$49.6	$40.4	32.9%	4	30	10%
4	260	0.072	300	$35.2	$3.7	0.0%	31.6	10	10%
4	260	0.072	300	$35.2	$8.5	0.0%	13.4	15	10%
4	260	0.072	300	$35.2	$13.1	12.8%	8.6	20	10%
4	260	0.072	300	$35.2	$17.9	18.9%	6.3	25	10%
4	260	0.072	300	$35.2	$22.6	24.8%	5	30	10%
5	30	5	60	$56.2	x	x	x	10	10%
5	30	5	60	$56.2	x	x	x	15	10%
5	30	5	60	$56.2	x	x	x	20	10%
5	30	5	60	$56.2	x	x	x	25	10%
5	30	5	60	$56.2	x	x	x	30	10%
6	96	0.028	250	$20.0	$3.3	0.0%	20.5	10	10%
6	96	0.028	250	$20.0	$7.3	12.0%	9	15	10%
6	96	0.028	250	$20.0	$11.2	20.9%	5.8	20	10%
6	96	0.028	250	$20.0	$15.1	29.6%	4.3	25	10%
6	96	0.028	250	$20.0	$19.0	39.3%	3.4	30	10%

SMES Business Cases – Price Differential Frequency of 10%






SMES BUSINESS CASES
PRICE FREQUENCY OF 10%
BREAK EVEN POINT (YRS.)
ENERGY PRICE DIFFERENTIAL ($/MWHR)
0
10
20
30
40
50
60
70
80
90
100
10
15
20
25
30
CASE NO. 1
CASE NO. 2
CASE NO. 3
CASE NO. 4
CASE NO. 6

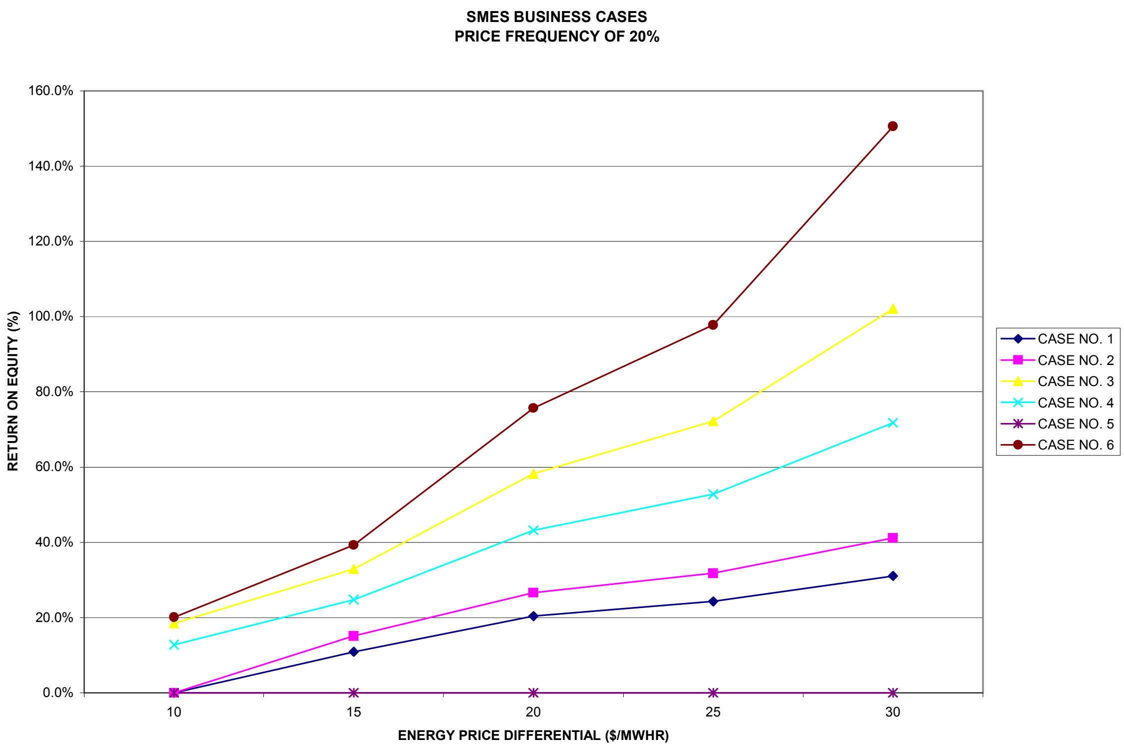
C

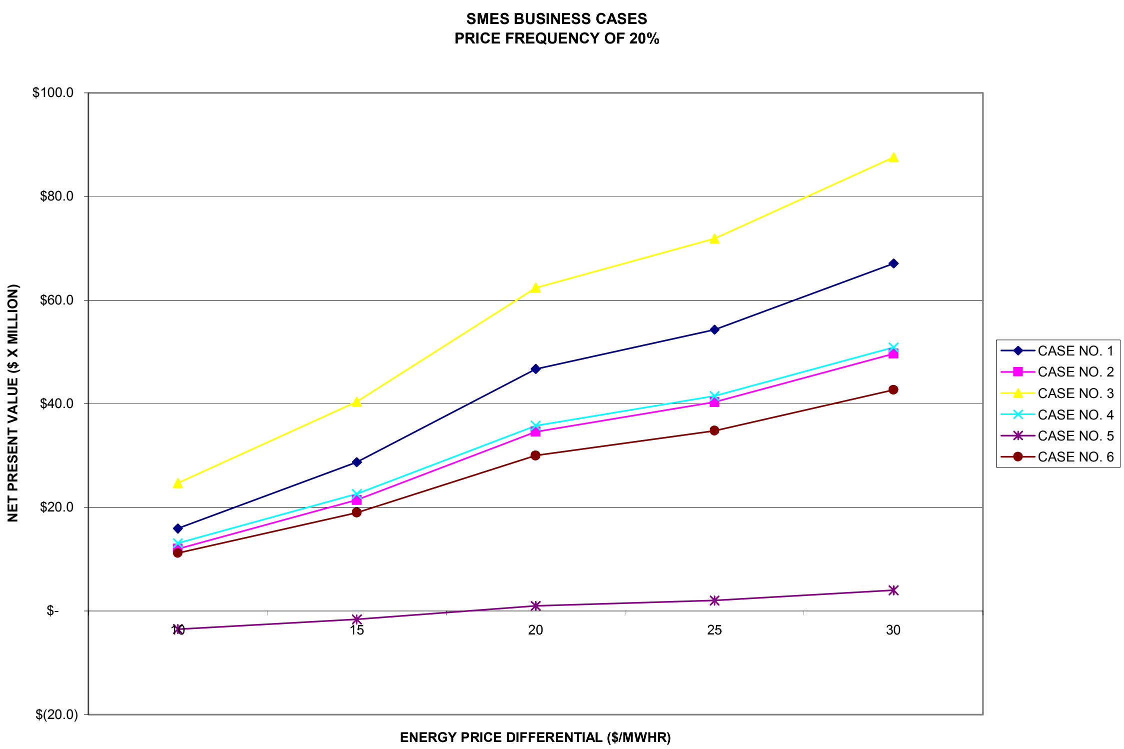
SMES BUSINESS CASES – PRICE DIFFERENTIAL FREQUENCY OF 20%

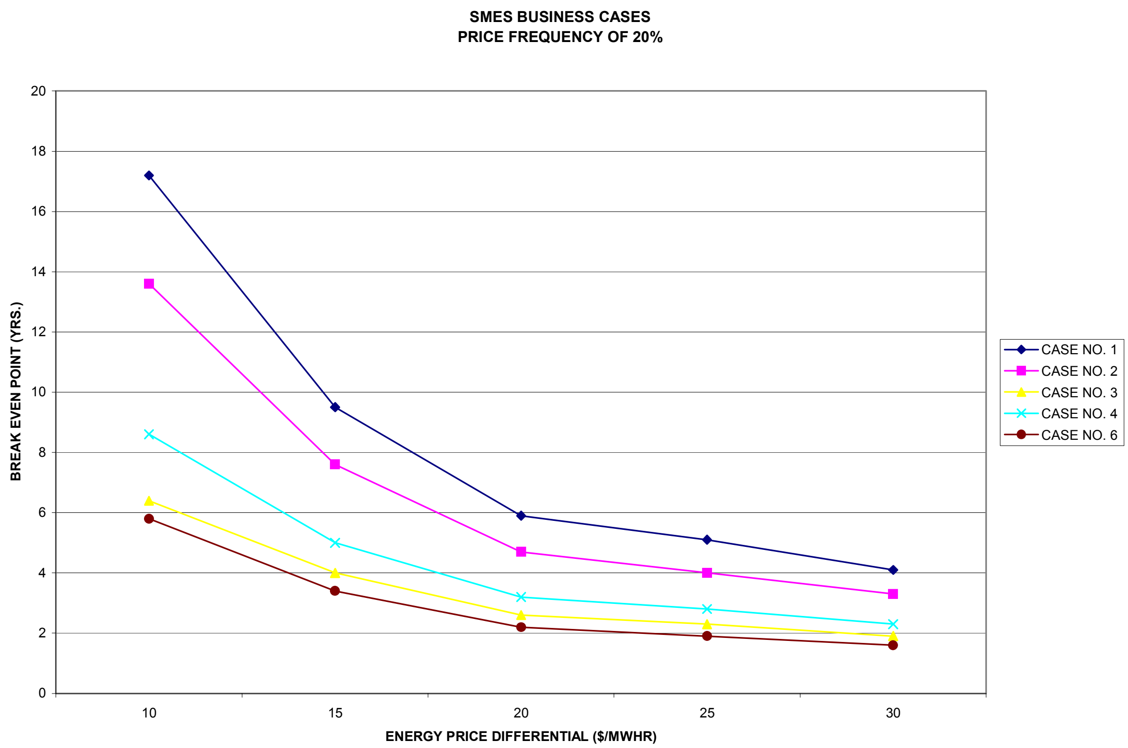
Table C-1
SMES Business Cases - 20% Price Differential Frequency

Case #	Power Capacity (MW)	Energy Storage (MWhr)	Transmission Enhancement (MW)	Cost ($xMillion)	Net Present Value ($xMillion)	Return on Equity %	Break Even (YRS.)	Price Differential ($/MWh)	Price Diff. Freq. %
1	900	1	407	$86.8	$15.9	0.0%	17.2	10	20%
1	900	1	407	$86.8	$28.7	10.9%	9.5	15	20%
1	900	1	407	$86.8	$46.7	20.4%	5.9	20	20%
1	900	1	407	$86.8	$54.3	24.3%	5.1	25	20%
1	900	1	407	$86.8	$67.1	31.1%	4.1	30	20%
2	500	1	300	$50.9	$12.0	0.0%	13.6	10	20%
2	500	1	300	$50.9	$21.4	15.1%	7.6	15	20%
2	500	1	300	$50.9	$34.6	26.6%	4.7	20	20%
2	500	1	300	$50.9	$40.3	31.8%	4	25	20%
2	500	1	300	$50.9	$49.7	41.2%	3.3	30	20%
3	480	0.133	500	$49.6	$24.7	18.5%	6.4	10	20%
3	480	0.133	500	$49.6	$40.4	32.9%	4	15	20%
3	480	0.133	500	$49.6	$62.4	58.2%	2.6	20	20%
3	480	0.133	500	$49.6	$71.9	72.2%	2.3	25	20%
3	480	0.133	500	$49.6	$87.6	102.1%	1.9	30	20%
4	260	0.072	300	$35.2	$13.1	12.8%	8.6	10	20%
4	260	0.072	300	$35.2	$22.6	24.8%	5	15	20%
4	260	0.072	300	$35.2	$35.8	43.2%	3.2	20	20%
4	260	0.072	300	$35.2	$41.5	52.8%	2.8	25	20%
4	260	0.072	300	$35.2	$50.9	71.8%	2.3	30	20%
5	30	5	60	$56.2	$(3.5)	0.0%	45	10	20%
5	30	5	60	$56.2	$(1.6)	0.0%	90	15	20%
5	30	5	60	$56.2	$1.0	0.0%	240	20	20%
5	30	5	60	$56.2	$2.0	0.0%	93	25	20%
5	30	5	60	$56.2	$4.0	0.0%	46.4	30	20%
6	96	0.028	250	$20.0	$11.2	20.1%	5.8	10	20%
6	96	0.028	250	$20.0	$19.0	39.3%	3.4	15	20%
6	96	0.028	250	$20.0	$30.0	75.7%	2.2	20	20%
6	96	0.028	250	$20.0	$34.8	97.8%	1.9	25	20%
6	96	0.028	250	$20.0	$42.7	150.6%	1.6	30	20%

SMES Business Cases – Price Differential Frequency of 20%





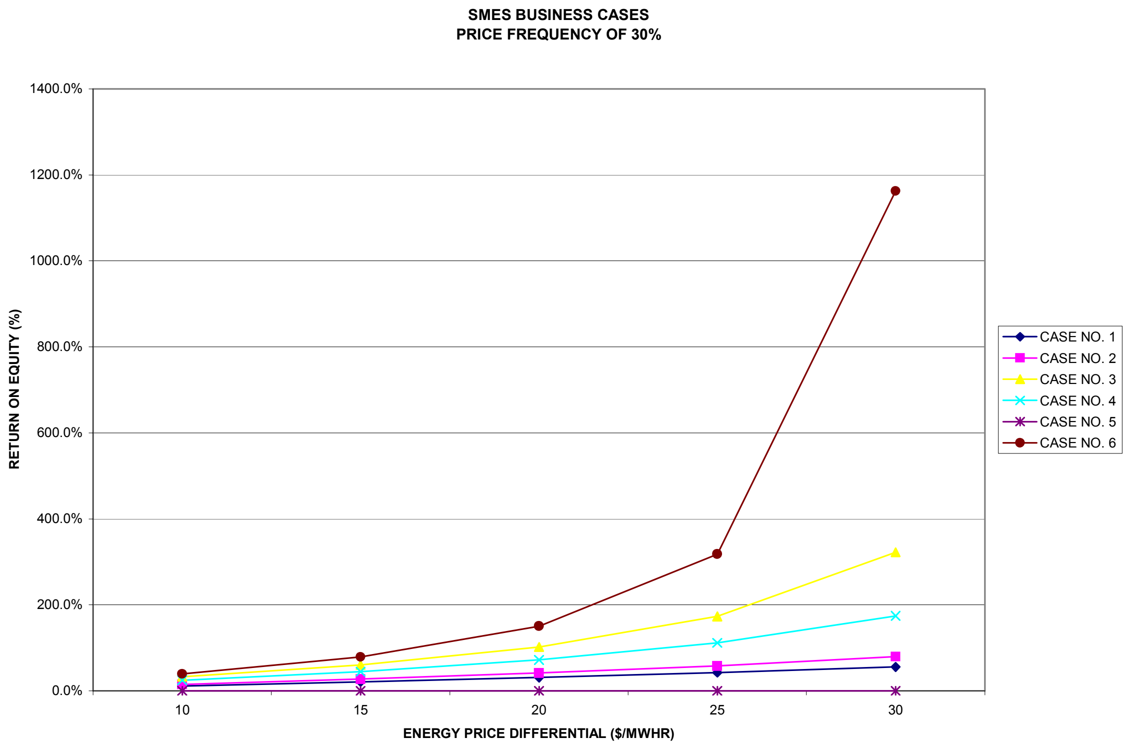

SMES BUSINESS CASES
PRICE FREQUENCY OF 20%
BREAK EVEN POINT (YRS.)
0
2
4
6
8
10
12
14
16
18
20
10
15
20
25
30
ENERGY PRICE DIFFERENTIAL ($/MWHR)
CASE NO. 1
CASE NO. 2
CASE NO. 3
CASE NO. 4
CASE NO. 6

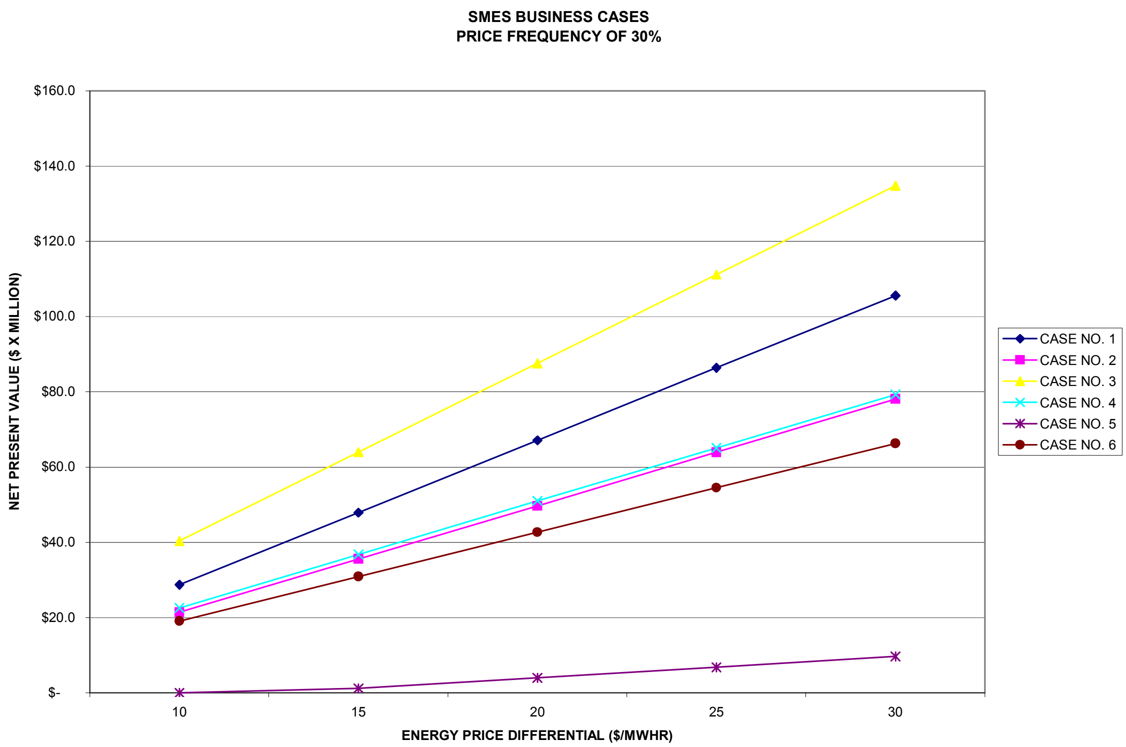
D
SMES BUSINESS CASES – PRICE DIFFERENTIAL FREQUENCY OF 30%

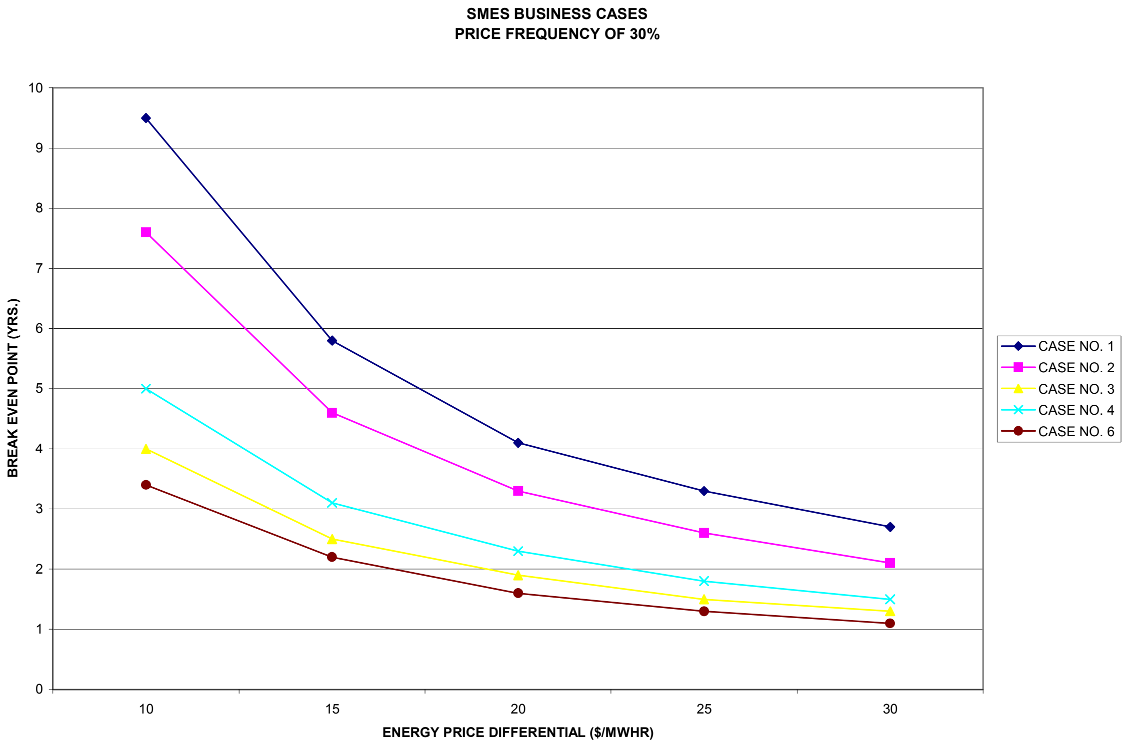
Table D-1
SMES Business Cases - 30% Price Differential Frequency

Case #	Power Capacity (MW)	Energy Storage (MWhr)	Transmission Enhancement (MW)	Cost ($xMillion)	Net Present Value ($xMillion)	Return on Equity %	Break Even (YRS.)	Price Differential ($/MWh)	Price Diff. Freq. %
1	900	1	407	$ 86.8	$ 28.7	10.9%	9.5	10	30%
1	900	1	407	$ 86.8	$ 47.9	21.1%	5.8	15	30%
1	900	1	407	$ 86.8	$ 67.1	31.1%	4.1	20	30%
1	900	1	407	$ 86.8	$ 86.4	42.4%	3.3	25	30%
1	900	1	407	$ 86.8	$ 105.6	55.6%	2.7	30	30%
2	500	1	300	$ 50.9	$ 21.4	15.1%	7.6	10	30%
2	500	1	300	$ 50.9	$ 35.6	27.5%	4.6	15	30%
2	500	1	300	$ 50.9	$ 49.7	41.2%	3.3	20	30%
2	500	1	300	$ 50.9	$ 63.9	58.0%	2.6	25	30%
2	500	1	300	$ 50.9	$ 78.1	79.3%	2.1	30	30%
3	480	0.133	500	$ 49.6	$ 40.4	32.9%	4	10	30%
3	480	0.133	500	$ 49.6	$ 64.0	60.4%	2.5	15	30%
3	480	0.133	500	$ 49.6	$ 87.6	102.1%	1.9	20	30%
3	480	0.133	500	$ 49.6	$ 111.2	173.3%	1.5	25	30%
3	480	0.133	500	$ 49.6	$ 134.8	322.2%	1.3	30	30%
4	260	0.072	300	$ 35.2	$ 22.6	24.8%	5	10	30%
4	260	0.072	300	$ 35.2	$ 36.8	44.8%	3.1	15	30%
4	260	0.072	300	$ 35.2	$ 51.0	71.8%	2.3	20	30%
4	260	0.072	300	$ 35.2	$ 65.1	111.3%	1.8	25	30%
4	260	0.072	300	$ 35.2	$ 79.3	174.6%	1.5	30	30%
5	30	5	60	$ 56.2	x	x	x	10	30%
5	30	5	60	$ 56.2	$ 1.2	0.0%	190.1	15	30%
5	30	5	60	$ 56.2	$ 4.0	0.0%	46.4	20	30%
5	30	5	60	$ 56.2	$ 6.8	0.0%	26.5	25	30%
5	30	5	60	$ 56.2	$ 9.7	0.0%	18.6	30	30%
6	96	0.028	250	$ 20.0	$ 19.1	39.3%	3.4	10	30%
6	96	0.028	250	$ 20.0	$ 30.9	79.0%	2.2	15	30%
6	96	0.028	250	$ 20.0	$ 42.7	150.6%	1.6	20	30%
6	96	0.028	250	$ 20.0	$ 54.5	318.1%	1.3	25	30%
6	96	0.028	250	$ 20.0	$ 66.3	1162.3%	1.1	30	30%

SMES Business Cases – Price Differential Frequency of 30%






SMES BUSINESS CASES
PRICE FREQUENCY OF 30%
BREAK EVEN POINT (YRS.)
ENERGY PRICE DIFFERENTIAL ($/MWHR)
0
1
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CASE NO. 1
CASE NO. 2
CASE NO. 3
CASE NO. 4
CASE NO. 6

Strategic Science and Technology Program

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