HTLS UPGRADES FOR POWER TRANSMISSION EXPANSION PLANNING AND OPERATION

by

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ABSTRACT

Renewable portfolio standards prescribe for penetration of high amounts of renewable energy sources (RES) that may change the structure of existing power systems. The load growth and changes in power flow caused by RES integration may result in requirements of new available transmission capabilities and upgrades of existing transmission paths. Construction difficulties of new transmission lines can become a problem in certain locations.

The increase of transmission line thermal ratings by reconductoring using High Temperature Low Sag (HTLS) conductors is a comparatively new technology introduced to transmission expansion. A special design permits HTLS conductors to operate at high temperatures (e.g., 200^{o}C), thereby allowing passage of higher current. The higher temperature capability increases the steady state and emergency thermal ratings of the transmission line. The main disadvantage of HTLS technology is high cost. The high cost may place special emphasis on a thorough analysis of cost to benefit of HTLS technology implementation. Increased transmission losses in HTLS conductors due to higher current may be a disadvantage that can reduce the attractiveness of this method.

Studies described in this thesis evaluate the expenditures for transmission line reconductoring using HTLS and the consequent benefits obtained from the potential decrease in operating cost for thermally limited transmission systems. Studies performed consider the load growth and penetration of distributed renewable energy sources according to the renewable portfolio standards for power systems. An evaluation of payback period is suggested to assess the cost to benefit ratio of HTLS upgrades.

The thesis also considers the probabilistic nature of transmission upgrades. The well-known Chebyshev inequality is discussed with an application to transmission upgrades. The Chebyshev inequality is proposed to calculate minimum payback period obtained from the upgrades of certain transmission lines.

The cost to benefit evaluation of HTLS upgrades is performed using a 225 bus equivalent of the 2012 summer peak Arizona portion of the Western Electricity Coordinating Council (WECC).

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NOMENCLATURE

ACCC	Aluminum conductor composite core
ACCR	Aluminum conductor composite reinforced
ACSR	Aluminum conductor steel reinforced
C_i	Generation cost at i^{th} generator
$C'_{Operating}$	Operating cost after transmission upgrades
$C_{Operating}$	Operating cost before transmission upgrades
$C_{Project}$	Upgrade cost
CR_i	Expectation of operational cost reduction
CSP	Concentrated solar power
$F(t)$	Probability distribution function
$f(t)$	Probability density function
FC	Fuel cost
FERC	Federal Energy Regulatory Commission
HTLS	High temperature low sag
MW	Megawatt
MVAr	Megavar
OPF	Optimal power flow
P_i	Active power output at generator i
$P_{i\ min}$, $P_{i\ max}$	Minimum and maximum active power outputs at generator i
$P_{line\ k}$	Active power flow at line k
PV	Photovoltaic

Q_i	Reactive power output at generator *i*
$Q_{i\ min}$, $Q_{i\ max}$	Minimum and maximum reactive power outputs at generator *i*
$Q_{line\ k}$	Reactive power flow at line *k*
R	Resistance of transmission lines
RES	Renewable energy sources
RPS	Renewable Portfolio Standards
$S_{line\ k}$	Thermal rating of k^{th} transmission line
SCOPF	Security constrained optimal power flow
$V_{i\ min}$, $V_{i\ max}$	Minimum and maximum voltages value at bus *i*
$\|Vi\|$	Voltage magnitude at bus *i*
VO&M	Variable operation and maintenance (cost)
WECC	Western electricity coordinating council
X	Reactance of transmission line
δ_i	Bus voltage angle at bus *i*
δ_{max}	Maximum voltage angle deviation across the line
Π	Payback period
μ_x	Mean value of variable *x*
σ_x	Standard deviation of variable *x*

Chapter 1. Introduction to HTLS Conductors

1.1 Background and Motivation

Transmission expansion in electric power system is a procedure by which large scale transmission system is designed to be reliable and feasible for future system loads. The problem of transmission expansion is complex due to the large number of variables, for example:

- Future load scenario;
- Availability of the rights-of-way;
- Future generation resource scenarios;
- Conductor types utilized;
- Technologies used (e.g. DC,AC, overhead, underground);
- Project cost.

Progressive penetration of distributed renewable energy sources has a positive influence on power transmission problem-solving. In the U.S. grids with competitive electricity markets, transmission congestion can become one of the impediment to possible electric power cost reduction. Progress in the smart grid development and integration of the distributed renewable sources can flatten the peak value of system load demand, thereby decrease electric power generation cost. Present costs of distributed renewable energy sources technology require excessive investment making impossible to attain the height of the renewable energy utilization. As a result, penetration of the renewable sources cannot facilitate transmission congestion problem significantly.

In terms of transmission expansion, in the United States, the main goal of the Federal Energy Regulatory Commission (FERC) is a promotion of electric power supply reliability and providing lower electricity cost for the costumers by reducing transmission congestions. Therefore, a well-considered transmission expansion should take into account possible operating cost reduction during upcoming operating period.

There are several factors that can impact transmission expansion:

Load growth

Load growth is a one of the main incentives for the transmission expansion. According to load growth forecast total electric energy consumption in U.S. will increase by 28% from 2011 to 2040 [1]. Development of the transmission infrastructure is an indispensable measure to meet the requirements for providing all the consumers with the sufficient electric power.

Renewable energy sources (RES) integrations

Integration of the renewable energy sources makes a great impact to the existing power grid. The Renewable Portfolio Standards (RPS) issued by DoE [2] requires the total power of at least 10% in 30 states to be generated by the renewable energy sources beginning from 2015. Installation of a high quantity of the renewable sources and ecological restrictions can force to shut down a significant portion of the conventional (coal, natural gas) power plants. Dislocation of the generation units can require an increase in transmission capability at certain parts of the system, particularly at the area where new generation units to be located.

Proximity to the sources of raw materials

Compared to the transportation of the fuel, transmission of the electric power is less expensive. Therefore, close location of the power plant to the fuel source can reduce electric power generation cost. Possible unbalanced distribution of the generation units and system loads can also be a reason of transmission congestion which requires system transmission expansion.

Obsolescence of existing transmission facilities

The existing transmission system has been built starting from the beginning of 20th century. The progressive electric power consumption and forecast on the upcoming load growth can require upgrades and improvement of the existing transmission system. The life span of typical transmission lines is 35-40 years [3]. By the end of the exploitation period, the transmission capabilities of these transmission lines often do not satisfy the increased load requirements.

All factors above stimulate the transmission system development. As a result higher investments and land are involved to increase transmission system capabilities. This thesis focuses on the revealing the circumstances favorable for High Temperature Low Sag (HTLS) conductor implementation and consequent economic benefits.

This chapter introduces the background of existing transmission systems, disadvantages of each type of conventional transmission expansion options and introduces comparatively new technology, known as HTLS conductors which can become a possible measure to increase transmission capability. A brief introduction of HTLS conductor features and implementations are provided.

1.2 HTLS Conductors

The HTLS conductors, such as Aluminum Conductor Composite Core (ACCC) and Aluminum Conductor Composite Reinforced (ACCR), are designed to operate at the temperatures as high as 200^{o}C, more than two times higher, comparing with conventional Aluminum Conductor Steel Reinforced (ACSR) conductors, which normally operate at 75^{o}C. The composite core of the HTLS provides additional strength to the conductor, which reduces the sag of the transmission line during the operation at high temperatures. Typically, such conductors are capable to conduct the current as high as 2 to 3 times comparing with conventional ACSR conductors of comparable cross-sectional area [4]. There is little difference in weight and diameter between HTLS and conventional ACSR conductors. The electrical features, namely per mile resistance and reactance, are comparable with ACSR. The transmission lines which can often become congested can be good candidates for HTLS implementation, since no upgrades of towers are required for the reconductoring. Another feature of the HTLS conductors is higher corrosion resistance, which can increase a life span for the upgraded transmission lines [5]. Additional disadvantages of HTLS upgrading include outage time, required for the upgrades; and a lower level of experience with HTLS as compared with conventional conductors.

The main disadvantage of the HTLS conductors is its high cost which varies from two to six times compared to comparable conventional ACSR conductors [6]. However, due to the similarity in physical supporting requirements, the reconductoring using HTLS does not usually require reinforcement of the towers, insulators or other equipment. This feature of lower or comparable weight of HTLS conductors may allow significant cost reduction for upgrading of existing transmission lines. Comparing with other types of transmission upgrades, a rapid reconductoring using HTLS conductors usually does not require long term line outage. In the research for this work, this advantage of HTLS technologies was mentioned by several U.S. transmission companies. The short time required for reconductoring allows for the facilitation of possible consequences of a long term outage. The typical transmission upgrades methods and their advantages and disadvantages are shown in Table 1.1.

Table 1.1 Comparison of different transmission upgrades methods

Upgrade Method	Advantages	Additional Expenses and Disadvantages
Parallel single circuit line	Possibility of operation during new line construction	Rights-of-way availability
Parallel line on existing towers	Lower transmission losses due to decrease in equivalent line resistance	Expenses for long duration of line outage Towers usually do not have appropriate design to carry parallel circuit
Voltage level increase	Lower transmission losses due to high voltage, low current operation	Line outage duration expenses Right-of-way availability Transformer cost
Reconductoring with HTLS	No upgrades in towers and insulators facilitates upgrade	Cannot increase security rating

As seen from Table 1.1, compared with conventional transmission upgrades, HTLS reconductoring may be a good option for increased thermal rating. Parallel single circuit construction and installation of a new parallel line on existing towers can also increase security rating of the transmission line due to decreased equivalent line impedance. A significant alternative is often redesign of an existing circuit utilizing a higher transmission voltage. The voltage increase method is also capable of increasing the security rating. However such types of upgrades often require additional rights-of-way which can be hard to attain. Of course, higher transmission voltage requires total replacement of transformers and adjacent equipment. For short transmission lines, security limitation is usually not a limiting factor. As illustrations, for the research for this thesis, most HTLS implementations were found to be of length less than 50 miles, and many were found to be less than 25 miles. For such lines reconductoring using the HTLS conductors can be a good option for transmission upgrades.

1.3 State of the Art for HTLS Conductor Applications

HTLS conductors are a comparatively new technology introduced in transmission engineering. A number of performed studies are based on revealing the advantages and disadvantages and the possibility of HTLS conductors implementation. A sampling appears below.

Reference [6] stated that during long term operation at high temperatures, the resistance of the conductor increases. In long heavily loaded transmission lines high ratio of the conductor resistance to reactance R/X can lead to transmission security limitation. The increased resistance may also require additional reactive power support on the receiving buses to keep the voltage level within acceptable ranges. On the contrary, the HTLS manufacturer Southwire data, reference [7], shows insignificant increase in resistance at high circuit currents.

Reference [8] stated that the increase in thermal rating of a reconductored transmission line can necessitate the upgrade of the subsequent transmission lines if they are not capable to meet higher power transmission requirements. The simulation results in [8] suggest that the effect of the transmission capability increase by the upgrading only one line is not significant.

Studies performed in [9] describe the impact of the magnetic field due to increased current in the conductor in HTLS lines. Even though in the U.S. in normal conditions, the conductor does not operate at high current permanently, contradiction with magnetic field requirements can be a barrier for HTLS utilization. The comparison of the initial installation cost and difference in sag at maximum operating temperatures are provided in [8].

According to [9], the ruling span method for calculating the sag of the transmission line gives unacceptable error if the conductor (including HTLS conductors) operates at high temperatures. A new method of computation of the conductors sag and tension provided in [10] for high temperature conductors. This study is particularly important when transmission line sag becomes a limiting factor for electric power transmission.

According to [11], there are generally three ways of transmission capability increase: application of *dynamic rating* which can increase thermal rating by 5-20%; conductor re-tensioning, with 20-50% increase in transmission capabilities; reconductoring using HTLS conductors with over 50 percent increase in thermal rating. In [8] Kopsidas et al. mentioned that the method of conductors retention has already been applied for most thermally limited conductors; therefore such method can hardly be applicable for contemporary transmission lines.

In [11] and [12], Kavanagh, Armstrong, Geary and Condon proposed the implementation of the HTLS conductors as an option to increase the transmission capability in order to meet the requirements of attaining 40% of Irish energy generation from renewable energy sources. When the rights-of way become difficult to attain, implementation of HTLS can become a suitable option.

The industry implementation of the HTLS conductors is described in [13]. The thermal rating of reconductored transmission lines is increased by over 100%. In the "Leon Creek to Pleasanton" project, the system wide transmission losses were *decreased* due to HTLS conductor application.

The model of the integration of the conductor ampacity monitoring and HTLS conductor implementation is developed in [14]. This model allows the evaluation of conductor sag at different circumstances to optimize the usage the conductor full thermal rating potential. Note that real time sag is often the ultimate limit of ampacity.

According to [15], the transmission capability in specific implementation was increased from 170 MVA to 450 MVA (+164%) after reconductoring conventional ACSS conductor 230 kV transmission line by HTLS. The short term emergency rating was increased to 500 MVA with duration up to 30 minutes for the upgraded transmission line.

1.4 Scope of the Thesis and Contributions

This thesis focuses on the comparison of the existing transmission expansion methods with implementation of HTLS conductors. The method of identification of congested transmission lines and beneficial economic conditions for HTLS conductor implementation is shown. The cost-benefit analysis of HTLS upgrades is performed.

Due to renewable energy sources integration, a portion of conventional generation units are likely to be retired or redispatched to lower operative levels. Therefore, the increase of transmission capabilities may be needed to accommodate these generation changes. Implementation of HTLS conductors should be considered in cases with high level of renewable energy resource integration. In this study, the change in transmission upgrades scenario is shown for cases with distributed energy resource integration.

The result of the studies provides useful information for transmission planning and cost-benefit assessment from the transmission lines upgraded using HTLS. The possible decrease in operating cost after a transmission line upgrade is studied, and the payback periods for the upgraded transmission lines are calculated.

A probabilistic model of the load growth is used in the thesis. The expectation of total transmission upgrade expenses is calculated in terms of the load growth forecast. The research is based on the reconductoring of existing transmission lines using HTLS conductors to assess its full potential as a transmission upgrade method.

1.5 Thesis Outline

Five additional chapters and appendix form the thesis. Chapter 2 provides descriptions of the methods which are used to identify the transmission lines – candidates for upgrade. Such lines are most likely to become overloaded beyond thermal rating. The thermally limited lines present active constraints in economic dispatch.

Chapter 3 proposes a method to calculate the minimum payback period for the transmission expansion projects. The evaluation of minimum payback period is based on Chebyshev’s inequality. The advantage of proposed method is an accuracy irrespective of system load distribution. The only values required are the forecasted load mean value and the standard deviation.

In Chapter 4 the simulation of the Arizona portion of the Western Electricity Coordinating Council (WECC) system with a summer peak load of 2012 is described. The transmission lines candidates for upgrades are identified. The decrease in operating cost and potential payback period are calculated for the identified transmission lines to provide the economic benefit resulting from the HTLS conductor implementation.

Chapter 5 represents the possibility of transmission upgrades using HTLS technology, considering penetration of renewable energy sources on the distribution level of power system. The results show the effect of transmission lines loading due to integration of RES in power system.

In Chapter 6 a summary of the main results of the thesis and suggestions of the future work is provided. Appendix A describes the Arizona portion of WECC system parameters.

Chapter 2. Identification of Transmission Lines for Upgrade

2.1 Transmission Expansion Considerations

The ability of transmission lines to carry bulk power depends on different factors such as thermal and security limits, conductor sag, voltage and transient stability. The thermal rating indicates a maximum current that can be transferred through a transmission line with no violation in sag. Security limits refer to maximum voltage phase angle difference across the transmission line to maintain synchronous operation of the system. The violation of security limits can lead to severe consequences during normal operation and especially in emergencies. Voltage stability refers to ability of the system to maintain voltages in a prescribed operations range at all buses in the system after being subjected to a disturbance from a given initial operating condition. The outage of a heavily loaded transmission line can be a reason for system stability loss. Therefore, the compliance with security constraints is necessary for a valid transmission expansion planning. Fig. 2.1 is a simple pictorial of their considerations. In this chapter, the aforementioned issues are integrated to identify those transmission circuits that should be upgraded.

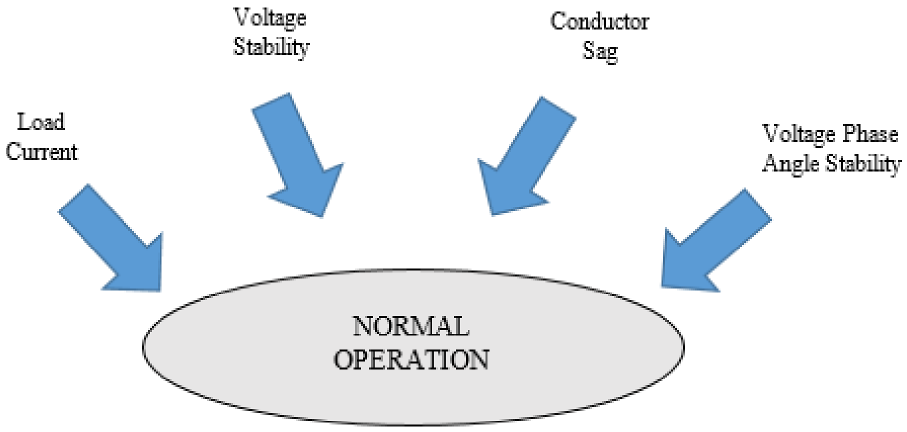

Figure 2.1 A pictorial of nominal operation of a transmission circuit

2.2 Methods of Transmission Capability Increase

Load growth, system deregulation, power marketing can be a motivation for power transmission expansion. Different methods of transmission expansion have their advantages and disadvantages. Followed by system reliability, the cost of transmission expansion becomes the most important factor for selecting an appropriate philosophy of transmission expansion. The main methods of transmission expansion increase are listed below with a brief description of these technologies:

Construction of new AC or DC transmission lines. This option requires high investments for transmission equipment and rights-of-way. New construction is especially suitable for long-term transmission expansion planning. The overhead construction of DC transmission lines is reasonable mainly for comparatively long lines due to inverter and rectifier construction expenses. In [16], the authors cite 500 km beyond which DC is often favored over AC. Reference [17] discusses advantages and disadvantages of DC transmission lines over AC.

Construction of the new transmission lines can also include utilization of underground cables. This option is suitable in urban areas where construction of the overhead transmission lines is complicated. Comparing with overhead transmission lines, underground cables offer a better protection against temporary outages. However, if the outage occurs, time required to locate the fault and repair underground cable requires more time and labor. Comparatively high cost of underground cables is also a significant impediment for its widespread implementation.

Reconductoring of existing transmission lines using conductors with higher thermal rating (including HTLS conductors). This method is suitable for those parts of the system where the thermal rating or the sag of existing transmission lines is a limiting factor of transmitted power. Usually, the use of higher ampacity conductors entails additional tower construction or modification. HTLS conductors, on the other hand, often do not require tower modifications. Reconductoring with no upgrades in towers and insulators reduces expenses for transmission upgrade. The high speed of upgrade is an advantage in HTLS designs since extended outages of key circuits may sometimes be avoided. The main negative aspect of HTLS upgrades related to the high cost of this technology. Reference [8] discusses the advantages and disadvantages of HTLS solutions.

High phase order systems. High phase order is a complicated technology that requires many unusual transmission engineering approaches such as: special and unusual transformer connections; protective relaying considerations; tower design; three phase to N-phase conversion ($N > 3$) and engineering expertise in this technology [18].

Voltage level increase. The advantage of this straightforward option is reduction in transmission losses. This option may be divided into two voltage upgrade ranges, for example increase of up to +15%, and increase of (usually substantially) more than +15%. For upgrade of operating voltage of up to +10% relatively few special considerations are needed. For example, in the Western U.S., 500 kV circuits are often operated at +10% high voltage. However, when simple operating policies are not enough to obtain the higher transmission capability that is needed planers may consider substantial increase in circuit voltages (e.g. converting a 138 kV circuit to 220 kV). High investments are required for increasing voltage level due to the installation of new transmission equipment and substation construction. Acquisition of rights-of-way for higher voltage level can be a problem in urban areas.

For congested transmission lines with comparatively low transmission capability, construction of new AC transmission lines or reconductoring of existing lines are usually applicable. A thorough analysis is required to identify the best option of system transmission capability increase in each particular case.

2.3 Method of Identification of the Transmission Lines to be Upgraded

The main purpose of transmission expansion is the increase of transmission capability and possibly reducing system operation cost. The main factors that have the largest impact on the transmission expansion decisions are system reliability improvement, economical effect (can be estimated as a payback period from new line construction or existing line upgrade), right-of-way availability, and public opinion. Among these factors, economic benefit is one of the most important indicators in selecting the optimal solution. This observation is the core concept since power engineering is often cost-to-benefit driven. Fig. 2.2 shows a rough comparison of time horizons for planning and operation in power engineering. The approach taken here is to perform transmission expansion at some time T in the future. And, the approach is to minimize the constrained operation cost at time T. In other words, the operating constraints and economic dispatch are done in operating real time at all points in the planning horizon.

During system operation, optimal generation dispatch can be limited by thermal rating of some transmission lines. However, operation can be improved by upgrading those transmission paths whose thermal ratings are the active limiting constraints during generation redispatch. Increase in thermal rating of such transmission lines alleviates thermal rating constraints, therefore allows better solution of the OPF. Upgrades can be performed by a wide range of transmission expansion strategies. In this discussion, implementation of HTLS technologies is used to replace conventional ACSR conductors. That is, the focus is completely on the potential use of HTLS solutions.

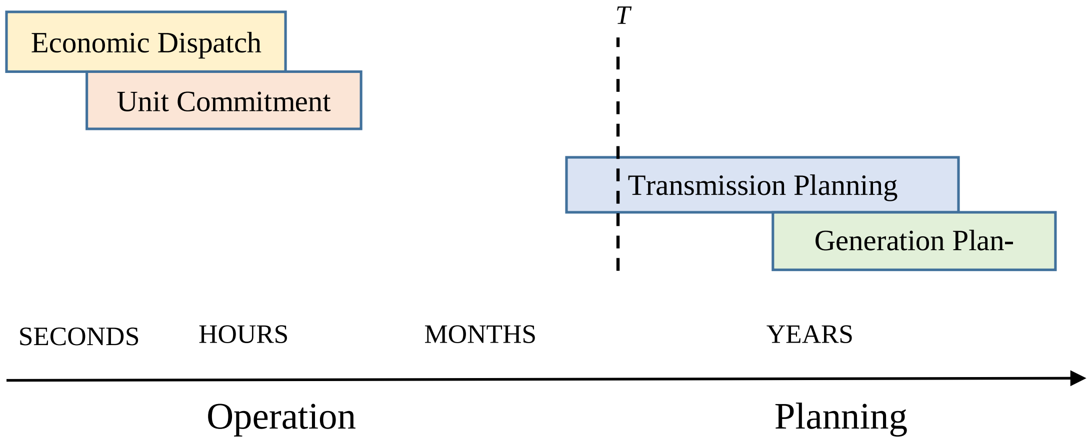

Figure 2.2 A pictorial of operating and planning time horizons

2.4 The Transmission Expansion Approach

For purposes of estimation of economic benefits afforded by HTLS implementation, define a payback period as an integrated period required to return the investment for reconductoring of an existing transmission line using HTLS technology. The payback period can be estimated by dividing the total investment spent for transmission upgrade by the decrease in system operation cost ($/h). The calculation of system operating cost decrease is carried out by the calculation of the difference between the operation cost before and after reconductoring,

$$\Pi = Payback\ period$$

$$= \frac{Project\ investments}{New\ operating\ cost - Old\ operating\ cost}$$

$$= \frac{C_{Project}}{C^{l}_{Operating} - C_{Operating}}$$

where $C_{project}$ is in dollars and $C^{l}_{Operating}$ and $C_{Operating}$ are in dollars per hour.

According to security requirements, all the system components should operate within their safe operating margins after the outage of any single component, i.e. it should be compliant with *N*-1 contingency requirements [19].

To calculate the decrease in operating cost resulting from a transmission upgrade, employ the following method: for an interconnected power system, the formulation of the AC OPF is

$$\min_{P_i} \sum C_i(P_i)$$

subject to

$$P_{i\,min} \leq P_i \leq P_{i\,max} \tag{2.1}$$

$$Q_{i\,min} \leq Q_i \leq Q_{i\,max} \tag{2.2}$$

$$|V_{i\,\min}| \leq |V_i| \leq |V_{i\,max}| \tag{2.3}$$

$$|P_{line\,k} + jQ_{line\,k}\,| \leq S_{line\,k} \tag{2.4}$$

$$|\delta_m\text{-}\delta_n| \leq \delta_{max} \tag{2.5}$$

where inequalities (2.1) and (2.2) represent requirements for active and reactive power generation at all generators i, inequality (2.3) represents bus voltage magnitude limits at any bus m, and (2.4) represents requirements for the thermal rating of all lines k. Note that $S_{line\ k}$ is the thermal rating of line k [20]. Inequality (2.5) represents the limits of voltage angle deviation across the transmission line for the purpose of system secure operation.

If a limiting factor of the OPF solution is (2.4). In this expression, the upgrade of the corresponding transmission line allows the alleviation of the active constraint, therefore providing a better solution of the OPF.

The following strategy is used for identification of those transmission lines that should be upgraded. The candidate lines for reconductoring should be identified as set Ω using a security constrained optimal power flow (SCOPF) technique. This yields a per hour operating cost. Then employing an SCOPF once more, allow the violation of one transmission line thermal rating in Ω under N-1 conditions. If the solution is found with no violation of any transmission line thermal rating, then, at the given system wide loading condition, the system economic optimal operation is possible with no line upgrades (no reconductoring). Otherwise (i.e., violations are found), define those transmission lines in Ω as candidates for reconductoring and perform reconductoring using HTLS. Again, note that the focus here is on HTLS and no other alternatives are considered. For purposes of this study, the resulting upgrade in the thermal ratings is by factor of two. This is the usual case because the ampacity of ACSR and comparable HTLS conductors are typically in the ratio 1:2, [4] . Subsequently, perform an SCOPF again. The process is repeated until there are no further limitations in thermal ratings. After each reconductoring, calculate the per hour generation cost. The process of defining candidate transmission lines for upgrading is shown in Fig. 2.3.

The decrease in operating cost is a key factor for the payback period calculation. Assume that the total cost of reconductoring for a certain line is known. Then the payback period can be estimated dividing the expenses for transmission line reconductoring by the decrease in per hour operating cost and load duration time.

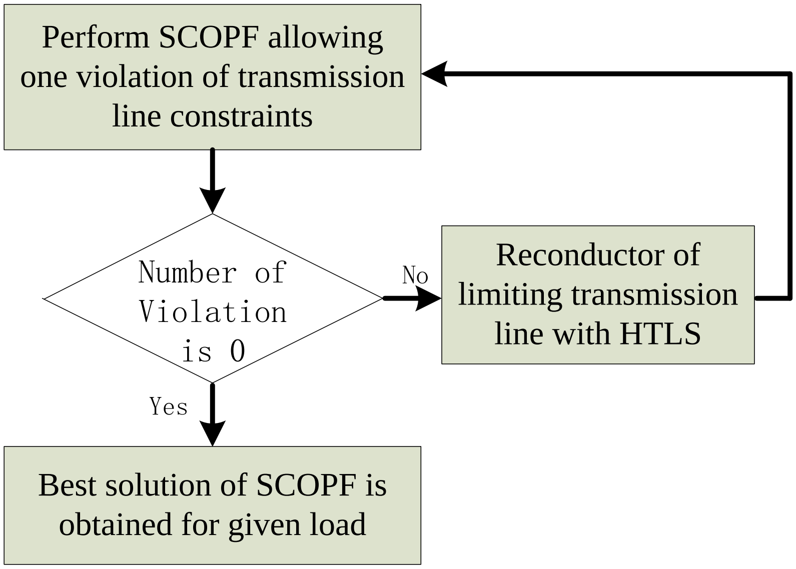

Figure 2.3 Basic strategy for the determination of transmission lines to upgrade

A quadratic cost approximation was used to estimate the cost of power generation. The operation cost adds up to the cost of power generation at all system generation buses. The objective is a minimization of system operating cost. Assume a quadratic cost approximation for power generation. The cost of generation power P at unit i is calculated using,

$$C_i = (A + BP_i + CP_i^2) \times FC + VO\&M \times P_i \tag{2.6}$$

where C_i is total generation cost in \$/h at generation unit i; P_i is the power generated at bus i in MW; A, B and C are cost coefficients or multipliers; FC is a fuel cost and $VO\&M$ is Variable Operations and Maintenance. The values of the multipliers are dependent on the generator type and were evaluated using historical data from the generating units. Table 2.1 presents the values of the coefficients for different generator types that are used in this work [21].

Table 2.1 Cost function multipliers for different generation types

(From [21])

Generation Type	A	B	C	Fuel Cost ($/Mbtu)	VO&M ($/MWh)
Coal fired	0	20	0.01	4.945	1.442
Nuclear	0	20	0.01	1.286	2.285
Natural Gas (Gas Turbine)	0	12.17	0.01	6.062	2.357
Natural Gas (Steam Turbine)	0	11.27	0.01	6.072	1.195
Natural Gas (Combined Cycle)	0	12.193	0.01	6.062	0.827
Hydro	0	10	0	1.00	1.287

2.5 Summary

This chapter discusses the methods of identification of the transmission lines targeted for reconductoring. The objective of transmission upgrade performance is the decrease in system operational expenses. The payback period is suggested to assess the effectiveness of HTLS technology implementation,

$$Payback\ period = \frac{Project\, cost}{New\, operating\, cost - Old\ operating\, cost}$$

The proposed transmission lines upgrade involve HTLS technology which can have benefit for both reduction of system operational cost (real-time operation) and a minimum cost solution of the transmission expansion problem (long term planning).

A basic strategy for the determination of transmission lines to upgrade has been proposed. This strategy based on three mail calculations:

- The SCOPF to identify transmission line constraints,
- Reconductoring critical lines and assessment of performance,
- Identification of the optimal solution.

Note that the analysis shown evaluates HTLS solutions only. Other transmission expansion strategies may give better results.

Chapter 3. Payback Assessment Using Chebyshev's Inequality

3.1 Chebyshev's Inequality

In probability theory, the Chebyshev's inequality relates to the dispersion of variants. The inequality guarantees that no more than $1/k^2$ fraction of the variant's values can be greater than k. The uniqueness of this inequality is that it holds true irrespective of the random variable probability distribution type. The original citation to Chebyshev's widely acclaimed work is [22].

This chapter proposes a method of assessment of transmission expansion based on Chebyshev's inequality. References [23] and [24] are small sampling of the literature that contains a discussion of Chebyshev's inequality, and [25] – [26], give examples of application.

3.2 Application to Transmission Expansion

One of the main incentives for the transmission expansion is system operation cost reduction. Load growth uncertainty is an important factor which should be considered during the transmission expansion planning. Due to the uncertainty, error in the power demand forecast can lead to significant deviation from the expected savings resulting from the transmission upgrades. Discovery of a method to estimate the shortest payback period obtained from transmission system upgrades is important for the evaluation of the transmission planning overall.

Due to uncertainty in load forecast, the load growth forecast problem is usually represented as a probabilistic model. Application of the probabilistic model based on Chebyshev's inequality may be suitable for the assessment of the economic efficiency obtained after upgrades regardless of the load distribution.

Chebyshev's inequality gives an upper bound for the probability that a random variable is greater than a certain value. The advantage of Chebyshev's inequality is the accuracy of the model irrespective of the distribution that random variable. A disadvantage is that the Chebyshev's inequality can only give the upper bound of the cited probability, but not its exact value. In this application, the random variable considered is the system-wide effective peak demand. Let X denote that peak demand. Since the forecasted load usually has unknown probability distribution, the model based on Chebyshev's inequality cannot guarantee the accuracy of the results. Implementation of a proposed model allows the estimation of the shortest expected payback period from a selected transmission upgrade method.

According to Chebyshev [22], for any random variable X with mean value μ_x and variance σ_x^2, the following inequality holds,

$$P\{|X-\mu_x| \geq t\} \leq \frac{\sigma_x^2}{t^2} \tag{3.1}$$

where $t \geq \sigma_x$. The Inequality (3.1) holds for any probability distribution function. Standardization of the random variable allows setting the mean value of the variable to be zero, and standard deviation to be one (i.e. standardized measure). As a result, (3.1) can be represented as

$$P\{|X'| \leq t\} = P\{-t \leq X' \leq t\} \geq 1 - \frac{1}{t^2} \tag{3.2}$$

where $X' = \frac{X-\mu_x}{\sigma}$.

In terms of the probability density function, Inequality (3.2) can be expressed as

$$\int_{-t}^{t} f(x)dx \geq 1 - \frac{1}{t^2}. \tag{3.3}$$

The value of the left hand part of (3.3) is the area below the curve of the probability density function *f(x)* between *–t* and *t* as shown in Fig. 3.1.

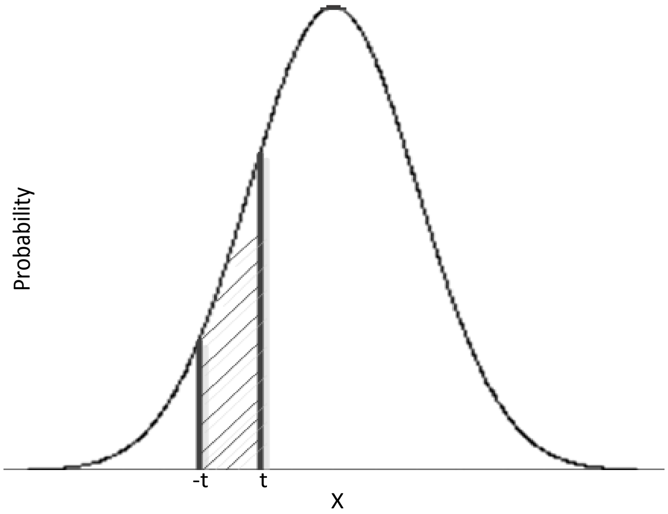

Figure 3.1 Probability density function. Value of (3.3) for a normally distributed variable

In general, the value of the function *f(x)* integrated from *–t* to 0 is not equal to the value of *f(x)* integrated from 0 to *t*, i.e.,

$$S_1 = \int_{-t}^{0} f(x)dx \neq \int_{0}^{t} f(x)dx = S_2$$

Let S_1-S_2 = ε. Then (3.3) becomes,

$$2[F(t)-F(0)]\geq 1-\xi-\frac{1}{t^2} \tag{3.4}$$

where $F(t)$ is a probability distribution function of $f(x)$ for the load $x = t$. For most cases, probability distribution function at $x = 0$ is not equal to 0.5. Define β as a deviation, i.e. the value of $F(t)$ at $t = 0$ is equal to $0.5+\beta$. Hence (3.4) becomes,

$$2[F(t)-0.5-\beta]\geq 1-\xi-\frac{1}{t^2}\,. \tag{3.5}$$

Or

$$F(t)\geq\frac{2+\lambda}{2}-\frac{1}{2t^2} \tag{3.6}$$

where 2β- $\varepsilon = \lambda$. A similar expression is derived for the left part of probability distribution function,

$$F(-t)\leq\frac{-\lambda}{2}+\frac{1}{2t^2}\,. \tag{3.7}$$

Expressions (3.6) and (3.7) show the upper and lower bounds of probability distribution model based on Chebyshev's inequality, for $t < 0$ and $t > 0$ respectively.

Assuming a symmetric probability distribution where $\varepsilon = 0$ and $\beta = 0$, Inequalities (3.6) and (3.7) become,

$$\begin{aligned} F(t) &\geq 1-\frac{1}{2t^2}\ (t\geq 1) \\ F(-t) &\leq \frac{1}{2t^2}\quad (t\geq 1) \end{aligned} \tag{3.8}$$

According to the Inequalities in (3.8), the function $P\{|X'| \geq t\}$ can be expressed as shown in Fig. 3.2.

With reference to (3.8), Fig. 3.2 shows the probability distribution function of the random variable which takes the value greater than parameter *t*. The Chebyshev's inequality bounds are shown as dash-dot line. According to Chebyshev's inequality, the probability distribution function curve for any kind of distribution lies between Chebyshev's bounds. That is, the distribution of a random variable *x* lies below the dash-dot line for $t \leq -1$; and the distribution of *x* is above the dash-dot line for $t \geq 1$. The dashed line on the plot is a probability distribution function for a normally distributed random variable, and the solid line is for normalized load data (i.e. standardized measure), taken from the actual demand at the PJM interconnection for 2012 [27].

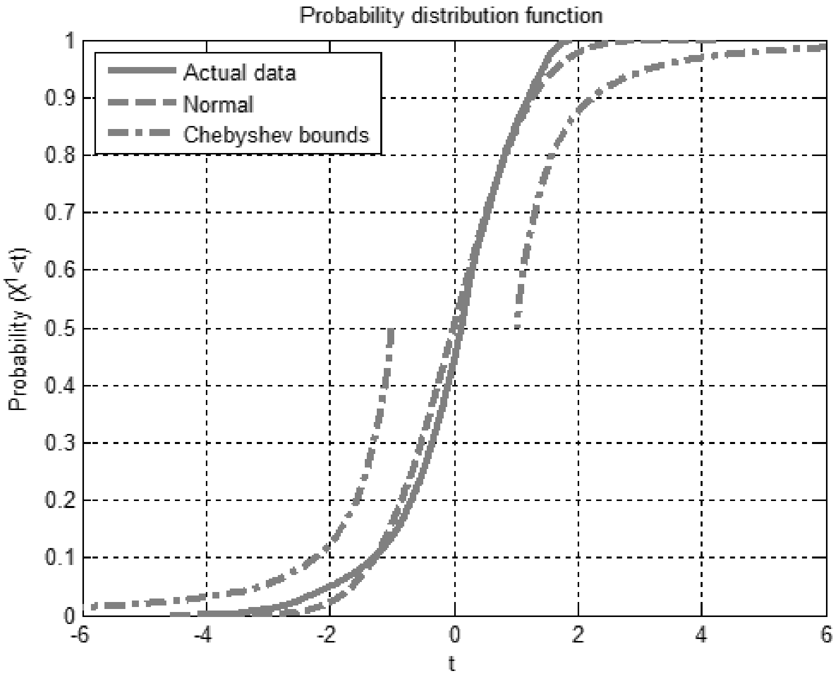

Figure 3.2 Probability distribution graph illustrating (3.8)

The method of expected payback period assessment is used to evaluate the economic effect from transmission upgrades. The operational cost reduction after performing the transmission system upgrades is a function of the load. For a normal distribution of the peak demand, probability density function is known. For Chebyshev's inequality bounds, probability distribution function curve is shown. The probability density function can be found by differentiation of the probability distribution curve.

For a random variable with given probability distribution, the probability distribution curve can be approximated as a piecewise linear function. Let random variable *X* be the system peak load. The operating cost reduction *c(x)* at load *X* = *x* is a function of *x*. The expectation of the operation cost reduction can be found by

$$\int_{-\infty}^{\infty} c(x) f(x) dx = c(x) F(x) |_{-\infty}^{\infty} - \int_{-\infty}^{\infty} F(x) dc(x) \tag{3.9}$$

where *f(x)* is probability density function, *F(x)* is probability distribution function expressed as a piecewise linear function and $c(x)F(x)|_{-\infty}^{\infty}$ is $c(\infty)F(\infty)-c(-\infty)F(-\infty)$.

The system operation cost increases with the load. Therefore, the higher the system load, the higher the cost reduction after performing transmission upgrades. The expectation of system operation cost reduction calculated using Chebyshev's inequality gives the highest cost reduction, i.e. the expected time for payback period is lowest. Therefore, the expected payback period assuming the Chebyshev's inequality bounds can be used as a reference for the shortest expected payback period from the transmission upgrades.

The value of Chebyshev type calculations of bound on payback period will be assessed further in Chapter 4 in which representative data will be used.

3.3 Summary

This chapter proposes a method of assessment of transmission upgrades. Having found the payback period according to the method described in Chapter 2, Chebyshev's inequality can further be used to estimate the minimum payback period for any upgraded transmission line. Transmission upgrades can be considered economically efficient if the payback period is close to the value obtained from Chebyshev's inequality. In practice, the payback period cannot be as short as a value obtained by Chebyshev's inequality since the Chebyshev value is the shortest *theoretical* payback duration. Knowledge of minimum payback period gives information on the adequacy of the investments to transmission system, therefore provided method can be a valuable tool for transmission expansion projects evaluation.

Chapter 4. Upgrade Case Studies Utilizing an Actual Transmission System as a Test Bed

4.1 HTLS Technology Implementation for the Arizona Transmission System

This chapter presents illustrative results achieved from implementation of the transmission upgrades method discussed in Chapter 2. The effectiveness of the method is based on the theoretical material described in Chapter 3. A 225 bus Arizona portion of the WECC system was used as a test bed to analyze the effectiveness of HTLS reconductoring. The 2012 summer peak load case was used as a base case with some system data "tuning" to insure that the base case is N-1 compliant. The data tuning was needed to avoid inaccuracy due to the equivalency of the actual southwest WECC system (e.g. equivalence of circuits below 100 kV, and omission of certain out-of-area interconnections). The base case studied was a reduced load case to insure N-1 compliance. A load growth study was performed to evaluate the reasonableness of HTLS implementation. No detail of the dynamic stability of the resultant system was considered except that the steady state line voltage phase angle differences were constrained to 30^o. The simulation was performed using PowerWorld software.

For the cited Arizona test bed, the load variation with time was not available. In order to obtain a realistic test, hour by hour actual load data from the PJM interconnection were used. To create a realistic scenario, the PJM data were scaled so that the annual peak value was identical to the 2020 forecast Arizona peak demand.

4.2 Cost Comparison of Transmission Upgrades

Expenses restrictions and difficulty in acquisition of new rights-of-way make transmission expansion a costly endeavor. The problem of rights-of-way acquisition becomes especially acute within urban areas. The use of HTLS offers an attractive uprating option since reconductoring of the lines on the existing towers does not require lengthy line outages. In many cases, the duration of the line outage during transmission reconfiguration is a key factor because the line outage can only be tolerated for certain system operating conditions. However, there are some conditions for which reconductoring with new tower placement may be a better option (e.g., according to WECC transmission capital cost studies [28], the transmission line per mile reconductoring cost with HTLS transmission lines is higher than construction of new lines). Table 4.1 illustrates this point. Note that in Table 4.1 and all subsequent tabular results, the Arizona transmission system is used as a test bed.

Table 4.1 WECC estimates of per mile costs for 230, 345 and 500 kV

Voltage	230 kV		345 kV		500 kV		
Equipment	single circuit	double circuit	single circuit	double circuit	single circuit	double circuit	HVDC bipolar
Base cost $/mi	$927K	$1484K	1298K	2077K	1854K	2965K	1484K
Multipliers							
Conductor							
ACSR	1.00	1.00	1.00	1.00	1.00	1.00	1.00
ACSS	1.08	1.08	1.08	1.08	1.08	1.08	1.08
HTLS	3.60	3.60	3.60	3.60	3.60	3.60	3.60
Structure							
Lattice	0.90	0.90	1.00	1.00	1.00	1.00	1.00
Tubular steel	1.00	1.00	1.30	1.30	1.50	1.50	1.50
Length							
> 10 mi	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3 – 10 mi	1.20	1.20	1.20	1.20	1.20	1.20	1.20
< 3 mi	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Age							
New	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Reconductor	0.35	0.45	0.45	0.55	0.55	0.65	0.55

K=1000

According to Table 4.1, calculate the different methods of transmission upgrade for selected transmission lines. The transmission upgrades cost comparison is shown in Table 4.2. Cost comparison of the three basic upgrade methods, i.e. HTLS reconductoring, new parallel line construction and new double circuit line construction, are provided. The transmission lines selected as candidates for upgrade are identified according to the method described in Section 2.3.

Table 4.2 illustrates that the reconductoring using HTLS technology is not the cheapest upgrade solution. Construction of new parallel single line is usually less expensive upgrade method. However, this upgrade method is infeasible due to the problems with rights-of-way availability.

Table 4.2 Upgrade cost for the selected transmission lines

Line name	Voltage level (kV)	Length (miles)	Transmission line upgrade cost (10^6 $)		
			HTLS Reconductoring	New parallel single line construction	New double circuit line construction
LCS – CNT	230	7.0	9.811	7.008	11.219
SAT – TRS	230	6.1	7.709	6.107	3.555
AFI-GLL	230	2.1	3.311	2.628	4.207
RRD-OOE	230	4.0	5.045	4.005	6.411
MMK-SSL	230	5.5	6.937	5.506	8.815
GLL-GDL	230	1.6	2.522	2.002	3.205

4.3 Effectiveness of HTLS Reconductoring

In this thesis, the evaluation of the of the transmission upgrades effectiveness methods is based on payback period. During load growth, there are certain transmission lines whose upgrade becomes necessary due to system topology. These upgrades do not impact on system operational cost even after reconductoring. An example of such reconductoring can be two parallel transmission lines supplying a load bus, as shown in Fig 4.1. Assume both Line 1 and Line 2 have similar thermal rating. If Line 1 becomes congested during the outage of Line 2, reconductoring of any (or both) of those lines will not decrease system operation cost since reconductoring does not affect the generation optimal dispatch. Calculation of the payback period for such transmission lines is not viable using provided method. Operation cost decrease is usually possible for those lines, which are located centrally in the interconnection.

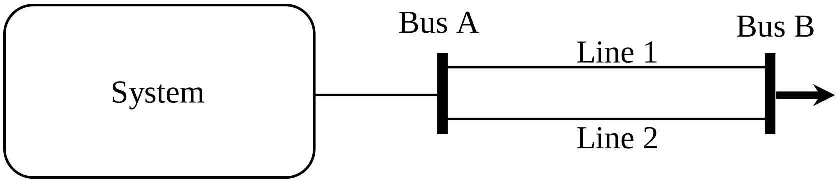

Figure 4.1 Example of the transmission line upgrade for which the calculation of payback period is not viable.

According to the method discussed at Section 2.3, during the load growth study, perform a SCOPF allowing violation in thermal rating of only one transmission line during *N*-1 operation conditions and calculate the decrease in operating cost after reconductoring that transmission line. The decrease in operating cost and payback period are shown in Table 4.3, assuming a constant system wide load value. The payback period, however, can be shortened significantly if the system operates at higher loads. For the reconductoring of those transmission lines which do not improve the solution of the SCOPF, assume that there is no. Such lines are not of research interest (e.g. Apache – Adams, Tucson – DelBac, DelBac – Nogales shown in Table 4.3).

Table 4.3 Transmission line reconductoring cost, reduction in operating cost at different peak periods

System load peak period (GW)	Transmission line and voltage level	Possible to avoid line overloading by redispatch	HTLS recond. cost (10^6\$)	Reduce in operating cost (\$/hour)	Payback period (years)
10.09	YVP –VRD (230 kV)	No	45.82	–	–
10.77	APC – ADM (115 kV)	No	–	–	–
10.87	LCS – CNT (230 kV)	Yes	9.811	149.48	7.492
11.26	TSS– DLS (115 kV) CLA –LLP (230 kV)	No No	– 66.739	– –	– –
11.56	DLC – NLS (115 kV)	No	–	–	–
12.15	LLP – CCC (230 kV)	No	61.48	–	–
12.44	SAT – TRS (230 kV) AFI – GLL (230 kV) RRD – OOE (230 kV)	Yes Yes Yes	7.709 3.311 5.045	38.03 52.01 82.96	23.14 7.26 6.94
12.54	MMK – SSL (230 kV)	Yes	6.937	42.87	18.47
13.22	GLL – GDL (230 kV)	Yes	2.522	9.15	31.46

In this study, reconductoring of transmission lines is performed when one of the lines becomes congested during *N*-1 contingency analysis, i.e. operates at 100% of its long term thermal rating. Test cases indicate that for a large scale system, upgrade of only one line does not change generation dispatch significantly. As a result, the impact from the reconductoring is low and the payback period is long. If load growth is considered, the impact from reconductoring may become significant. Reduction in operating cost and payback period at higher load levels for the indicated WECC test bed are shown in Table 4.4.

Note that in Table 4.4, the peak load period is accounted as either the full day (24 h) or a fraction of a day (namely 2 h for this study): this calculation is shown in the rows of the table separated by a solidus (i.e., a slash, /). For example, operational cost reduction achieved after reconductoring of transmission line LCS – CNT is 149.5 \$/hour, if the system wide load is 10.87 GW (111% of base case), and 2351 \$/hour, if the system wide load is 11.26 GW (115% of base case). The payback period shown in Table 4.4 is achieved assuming the system wide load increase right after reconductoring (i.e. static load growth study). For precise evaluation purposes, the dynamic load growth model is described in Section 4.4.

A typical transmission line life is 35-40 years [3]. Assuming that the peak load of the system is only two hours per day, the economic benefit becomes evident from Table 4.4. The benefits from decreased operating cost at non-peak load conditions are not considered. However, decrease in operating cost during non-peak load periods can also reduce the payback period further than those indicated in Table 4.4.

4.4 Transmission Upgrades Project Payback Period Evaluation

The benefits obtained from transmission upgrades often depend on system load forecast. Uncertainty in load forecast may cause the error in estimation of economic benefit achieved from the transmission upgrades. According to the method proposed by Section 3.3, economical assessment of the project by calculation of minimum payback period becomes possible. Knowledge on the project minimum payback period can also be desired to evaluate the adequacy of the investments to the transmission system.

Power system load growth is usually a probabilistic model. Transmission expansion planning engineers frequently use a normal distribution model to forecast system load. However, such models usually do not represent system future load precisely and may cause an error in the evaluation of economical aspect of the project. As an example, the difference between the real load distribution at PJM interconnection and normal distribution is shown in Fig. 4.2. In Fig. 4.2, the horizontal scale is the standard deviation.

Table 4.4 Reconductored transmission lines and payback period

Transmission line		System wide load (GW)						
		10.87	11.26	11.55	12.44	12.54	13.22	13.91
LCS – CNT	Savings $/hour	149.5	2351	3705	5218		31116	
	Payback period (years)*	7.49/89.9	0.48/5.71	0.30/3.62	0.22/2.58		0.04 /0.432	
SAT – TRS	Savings $/hour				38.03		3641	
	Payback period (years)*				23.1/278		0.24/2.90	
AFI – GLL	Savings $/hour				52.01		9505	
	Payback period (years)*				7.3/87.2		0.04/0.48	
RRD – OOE	Savings $/hour				82.96		1842	
	Payback period (years)*				6.9/83.3		0.31/3.74	
MMK – SSL	Savings $/hour					42.87	13736	14233
	Payback period (years)*					18.5/221.7	0.06/0.69	0.06/0.67
GLL – GDL	Savings $/hour						9.15	5816
	Payback period (years)*						31.5/377.5	0.05/0.60

*(Note: 7.49/89.9 means that the payback period is 7.49 years if the peak demand period is two hours (for every day) and the payback period is 89.9 years if the peak demand period exists for 12 hours each day)

A dynamic load growth model is used for evaluation of the transmission system upgrade project. The peak demand in 2012 is 16.32 GW and the mean value of the forecasted load in 2020 is 20GW [29], i.e. 1.28 times higher comparing with system peak load in 2012. To keep the system reliable operation and correspondence with N-1 contingency requirements, system load is decreased by 40%. For research purposes, the standard deviation for the forecasted load is set to 5%.

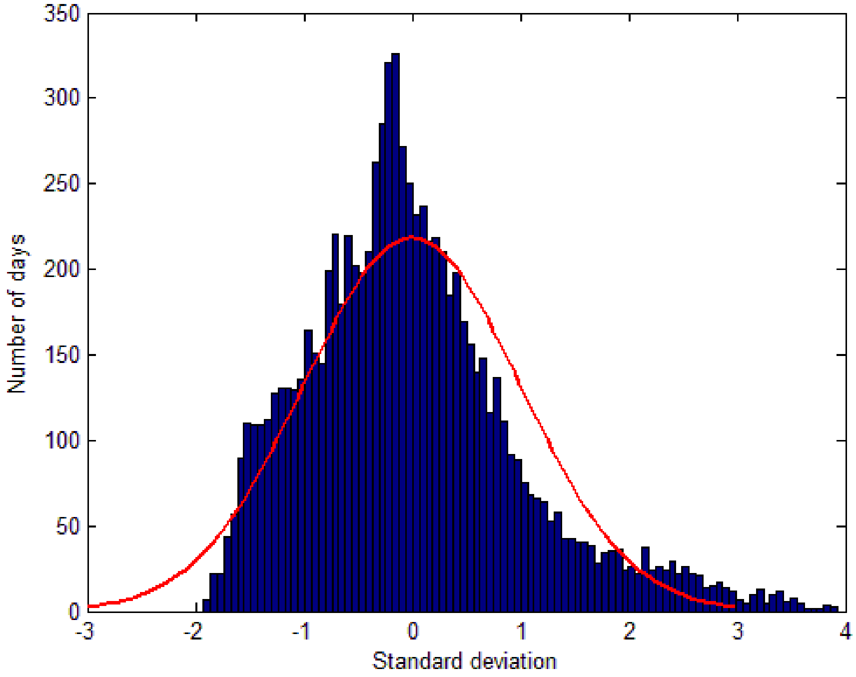

Figure 4.2 PJM system load (standardized), 2012

The assumption of equal load growth within even periods is appropriate for dynamic load growth modeling. Figure 4.3 shows the time when the reconductoring of identified transmission lines should be performed. According to Table 4.4, at system wide load equal to 10.87 GW, reconductoring of the transmission line LCS – CNT results in decrease of system operational cost. The system wide load with the mean value 10.87 GW is expected to be during the years 2014 to 2016. Therefore, to meet the system transmission requirements, reconductoring of this transmission lines should be performed before the end of 2014. Similarly, reconductoring of the other lines is performed before 2018 or 2020, depending on when the reconductoring would afford system operational cost decrease.

For calculation of the expected payback period, use the function of cost reduction in terms of system load, and system load growth probability density function. Then, the expectation of cost reduction for each upgraded transmission line can be calculated according to (4.1),

$$CR_i = \int_{-\infty}^{\infty} c_i(x) f(x) dx \tag{4.1}$$

where CR_i is the expectation of operational cost reduction for the transmission line *i*, $c_i(x)$ is a function of the operational cost reduction after reconductoring in terms of system load, *f(x)* is a system load probability density function and *x* is a system wide load. For calculation simplicity, the function of operational cost reduction is expressed as a piecewise linear function. It can be obtained by calculating operational cost reduction at different system wide load level according to Section 4.2. Part of the values can be seen in Table 4.4. For the comparison purposes, three different models of load distribution are used:

- Normal distribution;
- Chebyshev’s inequality model;
- PJM system 2012 year real load distribution model (assuming system load distribution change insignificantly yearly).

The probability density function for normal distribution is known. For the Chebyshev inequality and real load distribution models, analytical expression of probability density function is unknown. Therefore, for these two models, (4.1) can be calculated as,

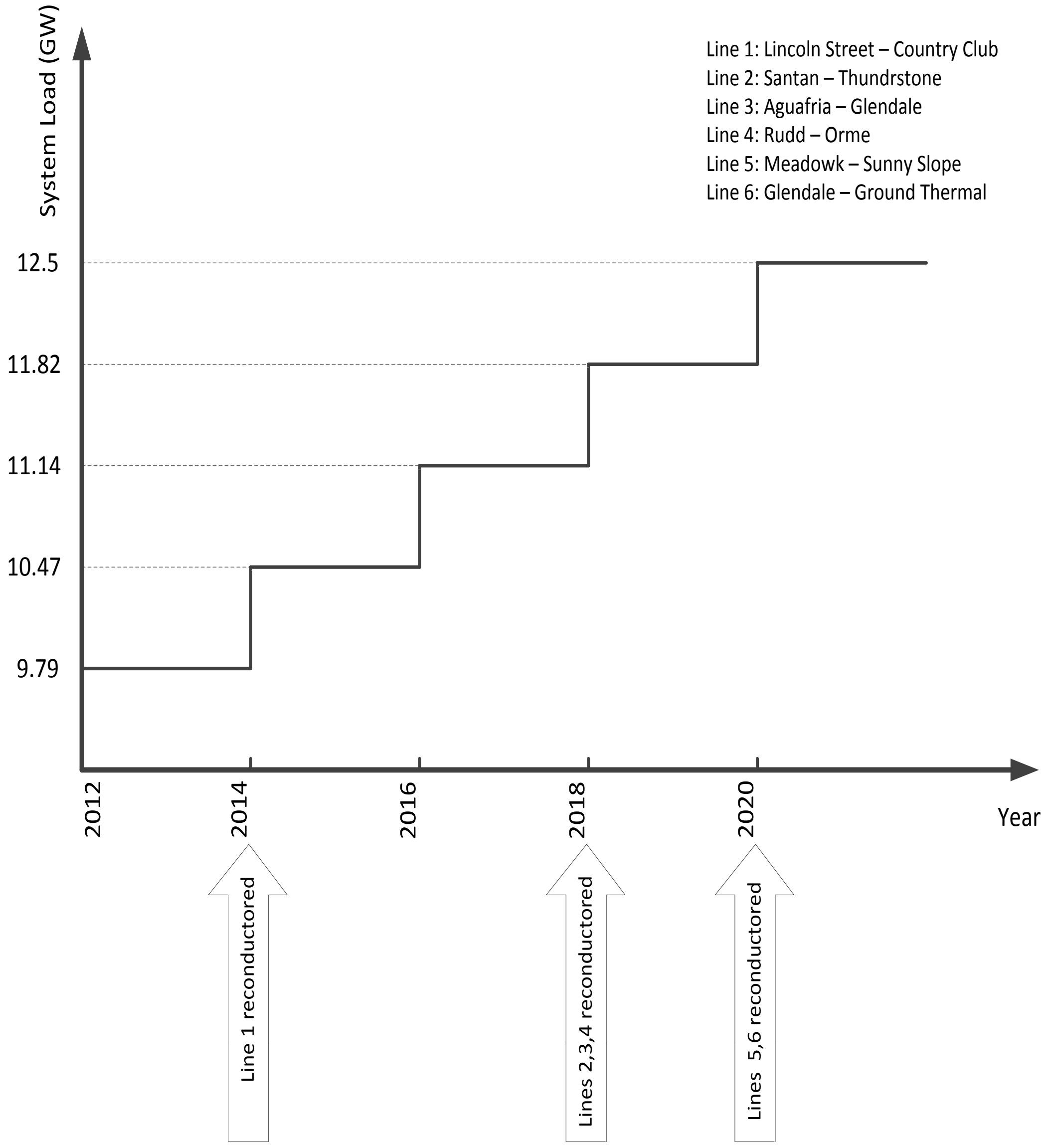

Figure 4.3 Transmission line reconductoring time during system load growth.

$$CR_i = \int_{-\infty}^{\infty} c(x) f(x) dx = c(x) F(x) |_{-\infty}^{\infty} - \int_{-\infty}^{\infty} F(x) dc(x) \qquad (4.2)$$

where *F(x)* is a probability distribution function. For real load distribution model, *F(x)* is known from the real data, and for Chebyshev's inequality model *F(x)* can be found according to (3.8).

For the proposed transmission upgrade project, six transmission lines are targeted for reconductoring. The cost reduction is supposed to begin immediately after performing the reconductoring of the first transmission line. Transmission line LCS – CNT becomes reconductored by the end of 2014. Therefore the payback period for the project begins from the year 2014. Since the system load increases gradually, the system operating cost also increases following the system load.

To estimate the payback period of the project, the calculation of the operational cost decrease afforded by each upgraded transmission line is required. Assume that the load growth is equal within two even time periods. Knowing the system peak load of 2012 and 2020, the estimation of the system load during each year during this period is possible. However, the system peak load during each year between 2012 and 2020 is uncertain due to the forecast error. Therefore it (i.e. system peak load) can be handled as a probabilistic model. The system peak load mean values for these years are shown in Tables 4.5, 4.6 and 4.7.

The calculation of the operational cost reduction allows estimation of expected revenue achieved from the transmission upgrades during these years. For instance, the mean value of system peak load in 2014 is 10.47 GW with 5% (0.524 GW) standard deviation. Having known probability density function *f(x)* or probability distribution function *F(x)* and operational cost decrease *c(x)*, calculation of the expected operational cost reduction for the upgraded lines becomes possible using (4.2). Sum up the expected operational cost reductions achieved by the upgraded transmission lines (in this case, before 2014 only one transmission line, i.e. LCS – CNT was upgraded), obtain the expected system operational cost reduction for 2014. Assume that the system operates at the peak load conditions 2 hours daily (730 hours per year). Multiply the expected operational cost reductions by number of hours operated during one year (730 hours) to calculate the revenue obtained from reconductoring during this year.

Similarly, the expected cost reduction and total revenue achieved from the transmission lines upgrades can be calculated for each year. The results for the 2014-2020 are shown in Tables 4.5 (calculations based on normal distribution load model), 4.6 (calculations based on Chebyshev distribution load model) and 4.7 (calculations based on real data distribution load model).

According to the Table 4.3, the total investments for the aforementioned six transmission lines upgrade is equal to 35.335 million dollars. The expected revenue achieved from the transmission upgrades during 2014 to 2019 for different types of load distribution are shown in Tables 4.3, 4.4 and 4.5. The expected revenue obtained before all the transmission lines become reconductored (2014 – 2019), and the non-recovered part of the investment is the difference between the total investments and revenue achieved during the years 2014 – 2019. The results are shown in Table 4.8.

Table 4.5 Expected operational cost reduction and total revenue

(Based on normal distribution load model)

Time period (Year)		2014	2015	2016	2017	2018	2019	2020
Load Mean Value (GW)		10.47	10.81	11.14	11.49	11.82	12.16	12.5
Expected operational cost reduction ($/h)	LCS – CNT	619	1144	1915	3262	5152	8278	12810
	SAT – TRS	—	—	—	—	204	556	1135
	AFI – GLL	—	—	—	—	528	1444	2956
	RRD – OOE	—	—	—	—	109	292	590
	MMK – SSL	—	—	—	—	—	—	3901
	GLL – GDL	—	—	—	—	—	—	304
	All upgraded transmission lines	619	1144	1915	3262	5993	10570	21696
Total revenue (10^6 $)		0.452	0.835	1.398	2.381	4.375	7.716	15.838

Table 4.6 Expected operational cost reduction and total revenue

(Based on Chebyshev distribution load model)

Time period (Year)		2014	2015	2016	2017	2018	2019	2020
Load Mean Value (GW)		10.47	10.81	11.14	11.49	11.82	12.16	12.5
Expected operational cost reduction ($/h)	LCS – CNT	1918	3094	3379	5225	8157	13294	16875
	SAT – TRS	—	—	—	—	742	1363	1790
	AFI – GLL	—	—	—	—	1925	2649	4672
	RRD – OOE	—	—	—	—	391	697	908
	MMK – SSL	—	—	—	—	—	—	6782
	GLL – GDL	—	—	—	—	—	—	1119
	All upgraded transmission lines	1918	3094	3379	5225	8215	18003	32146
Total revenue (10^6 $)		1.40	2.259	2.467	3.814	5.997	13.142	23.466

Table 4.7 Expected operational cost reduction and total revenue

(Based on real distribution load model)

Time period (Year)		2014	2015	2016	2017	2018	2019	2020
Load Mean Value (GW)		10.47	10.81	11.14	11.49	11.82	12.16	12.5
Expected operational cost reduction ($/h)	LCS – CNT	602	1137	1794	3188	5097	8155	12300
	SAT – TRS	—	—	—	—	181	524	1060
	AFI – GLL	—	—	—	—	469	1424	2758
	RRD – OOE	—	—	—	—	165	290	547
	MMK – SSL	—	—	—	—	—	—	3573
	GLL – GDL	—	—	—	—	—	—	446
	All upgraded transmission lines	602	1137	1794	3188	5912	10383	20684
Total revenue (10^6 $)		0.439	0.83	1.310	2.327	4.316	7.580	15.100

Assuming that the maximum system mean load is 12.5 GW, according to the payback period definition, divide non-refunded investment by the system operation cost reduction in 2020, obtain the system operation time left to achieve total payback. By adding 6 years (i.e., the years 2014-2019 which are the previous years of system operation) to the obtained value, one calculates the total payback period for the proposed transmission upgrade project. The calculated expected project payback period is shown in Table 4.8.

The results in Table 4.8 show that the minimum payback period calculated using Chebyshev's inequality is 16.6% shorter compared with the payback period calculated using the actual data distribution. However, system load distribution function depends on many factors, i.e. load distribution, generation availability, and climatic factors. The Chebyshev model guarantees that the payback period cannot be shorter than the value, calculated using the Chebyshev model irrespective to all these factors.

Table 4.8 Expected operation cost reduction and expected period for the transmission upgrade project

	Normal distribution model	Chebyshev model	Actual data distribution
Revenue during 2014-2019 (10^6\$)	17.155	29.079	16.802
Non-refunded investments (10^6\$)	18.18	6.256	18.533
System operation time left to achieve total payback	1.15 years	0.27 years	1.23 years
Expected project payback period	7.15 years	6.27 years	7.23 years

4.5 Active Power Losses in HTLS Transmission Lines

The high losses of HTLS transmission lines are a disadvantage, but it can only be an issue if conductors operate at high temperatures permanently. At the operating condition described in Section 4.3, HTLS conductors are used only to increase the emergency rating, but not for operating at high temperatures permanently. As a result, the overall increase of system losses is negligible.

In the United States, according to general operating policies, new HTLS transmission lines are not operated at high temperatures in long term operating scenarios, but only during emergency cases (e.g., line outage). Therefore, high losses are generally not an issue for HTLS conductors under this operating policy.

Based on the example provided in Section 4.4, in the system with total of 248 transmission lines, reconductoring of only six transmission lines increased the available transmission capability of the system by almost 50%. After performing the upgrades, the power flow mainly changes in the upgraded transmission lines, but not in the lines, located electrically far from them. Thus, at the given load value, the increase in losses caused by generation redispatch and transmission lines upgrades is insignificant.

As an example, at total system wide load of 1.11 times the base 9.7944 GW, during *N*-1contingency analysis, the 230 kV LCS – CNT transmission line becomes congested, i.e. runs 100% of its 607 MVA thermal rating. When the total system load is 1.35 times the base of 9.7944 GW, this upgraded transmission line with thermal rating 1214 MVA runs at 51.2% of its thermal rating. At the worst *N*-1 transmission outage case, the difference in the current is 2.04%. That infers that during the *N*-1 outage case, active power losses in

LCS – CNT increase only by 4.12%. Note that the N-1 outage case cited results are relatively small increase in system-wide active power losses. And the increase in active power losses is temporary. The high losses disadvantage of HTLS does not apply in this case.

4.6 Summary

The analysis based on Arizona transmission system shows the feasibility of system operational cost reduction after performing the reconductoring using HTLS technology. Among the six upgraded transmission lines, some are located in the urban area where the new rights-of-way are not attainable. Therefore the other methods of upgrades become unattractive due to higher cost or impossibility of implementation (such as parallel line construction).

The payback period for the cited upgrade overall is 7.23 years (assuming load forecast based on previous years data). However, depending on the real load distribution, the payback period may be shortened to 6.27 years. The shortest payback period is valuable information for the final decision of transmission upgrades performance. The estimated short payback period is an advantage in favor to the proposed method of HTLS technology implementation. There is, however, a possibility that the mean value of the real load distribution is significantly lower than forecasted load. Such a case can significantly extend the payback period, and the transmission upgrades performed according to the proposed method become ineffective.

This chapter also addresses the operational issue of active power losses caused by the HTLS utilization. Operationally, using present U. S. operating policy, the higher current in HTLS conductors does not cause significant system active power loss increase. The reason is that in the proposed upgrade method, only a few transmission lines are suggested for reconductoring (e.g., in the given example, only six of 248 transmission lines are upgraded). Therefore in scope of the system overall, increase in active power loss may be insignificant. Further, the use of HTLS conductors to their substantially higher current rating is effectuated only for a few hours per year: this is a consequence of the use of the higher current paths only as N-1 considerations so require. Therefore, again, one concludes that under the applications envisioned, excess active power losses may not be a significant factor.

Chapter 5. HTLS Technology and Renewable Energy Sources Integration

5.1 Analysis of the Impact of Distributed Energy Sources Integration on Transmission

In concordance with the renewable portfolio standards, 15% of the total generation in Arizona should be produced from renewable energy sources by 2025 [2]. As a result, a large amount of energy is expected to be generated from photovoltaic (PV) and concentrated solar power (CSP) plants. CSP generation is likely to be in the 280 MW range, (e.g., near Yuma, the Solana plant is at or near completion) [30]. A large number of smaller PV installations are also expected. Since PV generation units are also adopted through low voltage distribution systems, an interface is needed to connect to the transmission grid. Large central station, utility scale PV and CSP as well as residential scale PV result in changed use of the transmission system. This fact suggests a reassessment of the transmission system loading. Integration of renewable generation in the given system may require an upgrade of part of the transmission system. In either case, CSP or PV energy may require substantial transmission expansion or upgrading. Note that large central station fossil fuel plants are often located far from load centers. The development of PV resources is expected to be distributed at the load center itself. This change in location of generation is a reason for focusing on specialized needs in transmission expansion. This chapter introduces the possibility of HTLS technology utilization at the circumstances with the penetration of a large amount of renewable energy sources.

In this study, the impact of widely dispersed residential PV generation is studied. Note that CSP generation is basically the same topologically as fossil fuel generation. That is, this is concentrated generation. It is possible that new transmission resources will be needed to accomplish CSP plants, but the transmission engineering procedures are not really different from these utilized to accommodate coal plants. For this reason, CSP resources are not considered further. Rather, PV generation is assumed to be located near load buses.

5.2 Integration of Renewable Energy Resources

The Arizona transmission system introduced in Chapter 4 is used as a test bed. The solar PV is assumed to be only in the Phoenix metropolitan area – mainly residential roof top PV. The PV generation is assumed to be collected at substation buses. The power level of the applied PV generators on each bus is selected proportional to the total load at that bus. To keep the system total load unchanged, traditional generation of an equal amount to the added PV power must be reduced or decommitted. For illustration purposes, the Four Corners coal generation has been chosen to be decommitted since the three units at Four Corners, or about 1540 MW are expected to be closed by 2014 [31].

In the illustrative example shown in this chapter, four cases have been reviewed: a total generation of 560 MW, 750 MW and 1310 MW at the Four Corners power plant is replaced by distributed generation units connected through the 230 kV buses in the Phoenix metropolitan area. Note that there is no intended implication that centralized solar plants are unimportant, but the focus of this study is strictly on roof top PV. For this reason, the test beds indicated are designed as stated above.

5.3 A Comparison of Transmission Expansion Using Conventional Overhead Conductors

Among the solutions to increase system transmission capability is the construction of parallel lines to complement existing lines. A further alternative is the construction of new towers which are capable of supporting two parallel circuits. Both of these solutions require supplementary conditions: the first option requires attainable right-of-way, the second option will require temporary outage of the line intended to be upgraded. If both of these requirements cannot be fulfilled, HTLS reconductoring can become a viable solution. A further option is the increase of voltage level of the existing transmission path. However, in terms of economic efficiency, and the intended focus on HTLS, this option is not considered in this study.

In the performed studies, the distributed energy resources are located near the load buses. A significant portion of generated power at these buses is not required to be transferred to the other parts of the system but consumed locally. As a result, distributed location of low power energy resources can lead to transmission loss reduction and decreased loading of some transmission lines. If these transmission lines were targeted for upgrade with no consideration of future power generation units, the objectivity of the upgrades can be doubtful because the penetration of distributed energy sources may affect transmission upgrades planning significantly. This section analyzes the reasonableness of the performing transmission upgrades taking into account high penetration of renewable energy sources.

For these studies the load growth is assumed. The same studies as described in Chapter 4 are performed. The only difference is that the portion of the generating units at

Four Corners (coal power plant) is substituted by renewable energy sources (PV) with no assumed change in operating cost.

At this point, the cases of committing a total of 560, 750, 1310 MW of solar generation, and decommission of the same generation capacity at Four Corners are described. Table 5.1 shows the upgrade cost and the system load at which the upgrades are performed. The results are also depicted in the step diagram in Fig.5.1.

Table 5.1 Upgrade cost for the cases with substitution of traditional steam generators by distributed generator units

Peak system load (GW)	Total power of generation units at Four Corners substituted by PV generation units			
	Base case (No PV)	560 MW	750 MW	1310 MW
	Upgrade cost (10^6\$)	Upgrade cost (10^6\$)	Upgrade cost (10^6\$)	Upgrade cost (10^6\$)
10.87	9.81			
10.97		7.71		
11.26			7.71	
11.75			9.81	7.71
11.95				11.95
12.25		9.81		
12.44	7.71 3.31 5.05			
12.54	6.94			
12.63		3.31		
13.22	2.52	6.94	6.94 3.31	9.81
13.81		2.52		
13.91	4.49			
Total upgrade cost ($10^{6\,\$}$)	39.83	30.29	27.77	29.47

The transmission lines indicated in Table 5.1 are recommended to be upgraded using HTLS conductors due to comparatively low cost and close location to the urban area.

As mentioned in Chapter 4, these upgrades can reduce system operating cost and the payback period can be calculated. The transmission lines that do not decrease system operating cost are more likely to be upgraded utilizing different upgrade techniques. Such a decision can make the upgrade expenses lower compared to the reconductoring using HTLS technology. For the example test bed cases, the load growth in all considered cases is identical. The transmission lines that do not decrease system operating cost should be upgraded at the same system wide load value (e.g. as shown in Table 4.3, transmission line YVP –VRD should be upgraded when system wide load reaches the value 10.09 GW. The load value at which YVP –VRD should be upgraded is the same for the base case as well as for the cases with distributed energy sources penetration). Such transmission lines are of no interest in this thesis. The transmission upgrades cost versus system wide load is shown on Fig. 5.2. Only transmission lines that may have “payback period” are considered.

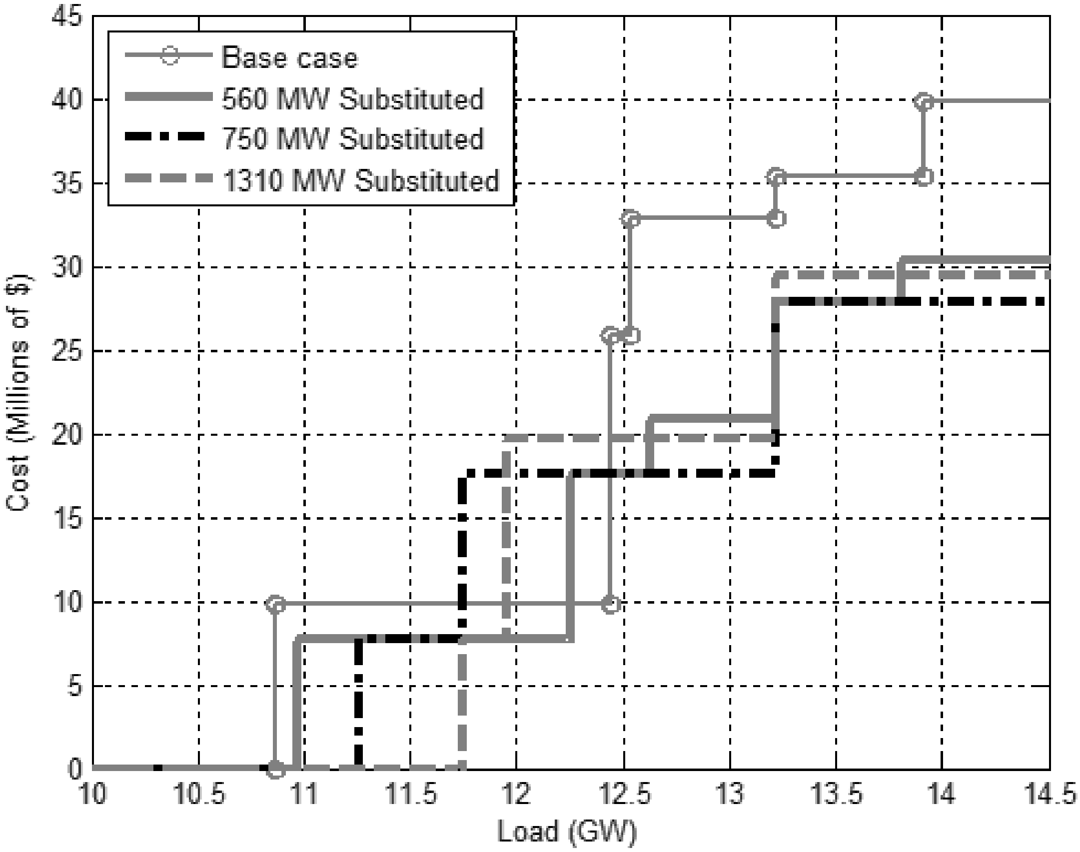

Figure 5.1 Pictorial of investments required for transmission upgrades

The results in Table 5.1 show that the transmission lines targeted for the upgrades can vary significantly depending on the capacity of distributed energy sources. A higher capacity of the distributed energy sources does not necessarily lead to less expenses required for the transmission upgrades. In addition, in the cases with the distributed PV generation units considered, the integrated payback period for the transmission upgrade project can be short. This is the case since the system wide load at which the first transmission line becomes upgraded is significantly higher than in the base case with no PV generation considered. That means that integration of distributed energy resources can afford operation at higher system wide load without transmission upgrades.

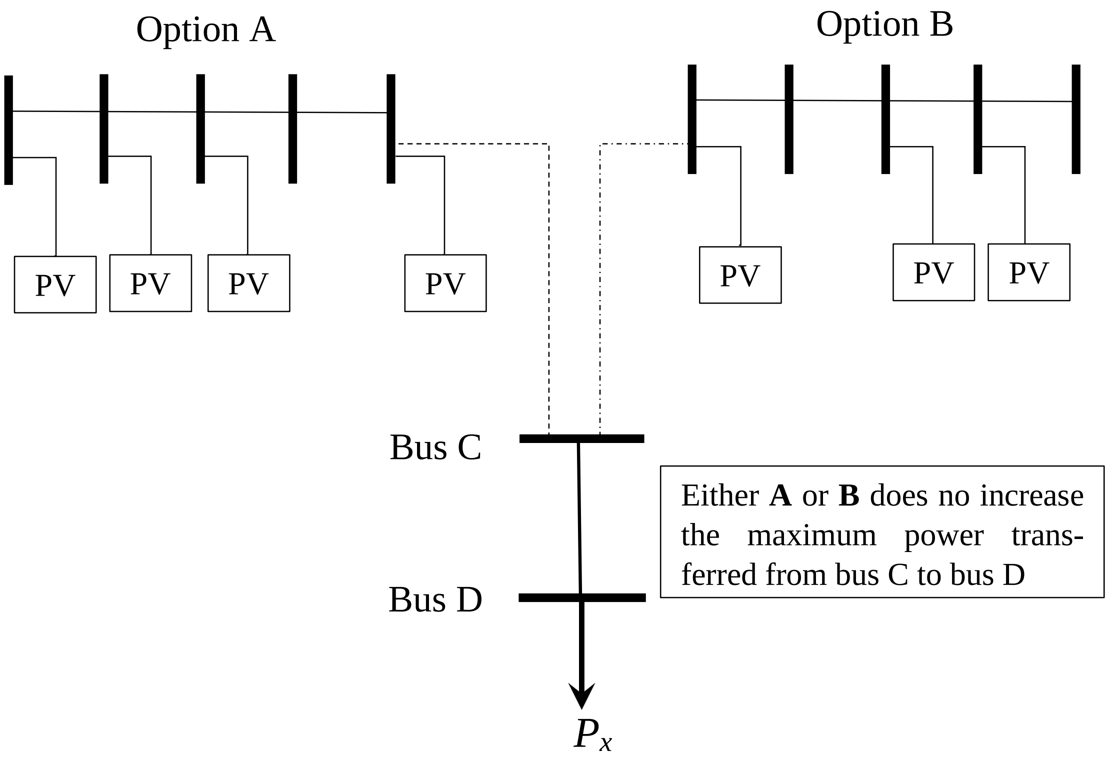

Figure 5.2 A pictorial of the addition of PV remote from the load center

5.4 Summary

This chapter describes the effect of the penetration of distributed renewable energy sources on transmission systems. The simulation results show that high expected amount of distributed energy sources may have a significant effect on transmission upgrades. The upgrade of some transmission lines becomes unnecessary due to the decreased line loading. The rescheduling and redistribution of generation as a result of integrating renewable generating resources may require transmission upgrades and these upgrades may require less expenses than generation rescheduling.

Since distributed generation units are installed at a comparatively low voltage level, and the generated power mainly is consumed locally, the need for upgrading high voltage transmission lines may not materialize.

Consideration of generation and load in transmission expansion engineering are examples of date and assumption embedded with uncertainty. The entire transmission expansion process involves multiple objectives and many requirements. Therefore, for minimization of the investments on transmission upgrades, every specific feature of the system (e.g., rights-of-way availability, maximum duration of line outages) and the benefits obtained from the system upgrade (e.g., system reliability, economic efficiency) should be carefully assessed.

Chapter 6. Conclusions

6.1 Main Conclusions

This thesis suggests a method of identification of transmission lines which should be upgraded using HTLS conductors in compliance with system secure operation requirements. Implementation of HTLS upgrades may decrease the operational cost of the system under recommended operation conditions. This is a consequence of the alleviation of transmission loading constraints. Reconductoring with HTLS can be reasonable for those cases where the thermal rating of existing transmission lines is a limiting factor of the security constrained optimal power flow. The reasonableness of the reconductoring, estimated as a payback period, varies depending on the system load growth and existing system transmission line loading.

The utilization of Chebyshev's inequality was proposed to evaluate the economical aspect of the transmission expansion projects. The results show that the minimum payback period estimated using Chebyshev's inequality does not significantly deviate from the payback period, estimated using real load data distribution. The advantage of proposed model is the accuracy of minimum payback period estimation regardless of system load distribution.

The main advantages of HTLS technology are the reduced right-of-way requirement and the short duration of transmission upgrade projects. Capability of HTLS to operate at higher currents can significantly decrease system operational cost and surpass the negative effect from high one-time expenses required for HTLS conductors. Even though HTLS can conduct higher currents, if the nominal operation of the transmission system does not utilize the additional ampacity of the HTLS upgrades, there will be no expected increase in transmission losses. This is the usual operating strategy in North America. The higher ampacity ratings of HTLS, under suggested system operation, are used only for operation during contingencies.

Utilization of HTLS for reconductoring of single transmission line located centrally in the interconnection not likely to allow permanent operation at high current (e.g. 200^{o}C). The reason is that the loss of a heavily loaded HTLS line can lead to the overloading of nearby lines.

The upgrade cost of the existing transmission lines using HTLS can be lower than the construction of some types of new transmission lines. The supplementary requirements for HTLS reconductoring are often less intrusive than for other transmission expansion alternatives.

This work analyzed HTLS conductor utilization assuming high penetration of distributed renewable energy sources. Location of the distributed RES at residential level may decrease the loading of some transmission lines and increase the loading of the others. Installation of RES at low voltage buses may decrease the loading of some high voltage (e.g. 345 kV) long transmission lines so that the upgrade of these lines becomes unnecessary. Instead, the lower voltage level transmission lines (e.g. 115 kV, 230 kV) may become overloaded. Since such transmission lines require less investments for the upgrades, HTLS becomes a viable option for the transmission investments.

6.2 Recommendations for Future Work

This thesis is focused on the economic analysis of HTLS implementation in AC transmission systems for the purpose of decreasing system operating cost. The following studies could be performed to fully evaluate the possibilities of further implementation of HTLS conductors:

- Consideration of conductor degradation and effect on generation dispatch;
- Impact of power storage on transmission loading;
- Investigate the possibility of HTLS to afford loading at *N*-1-1 contingency cases;
- Studying the effect of HTLS conductors on system stability due to the increased resistance at high temperatures;
- Possibilities of HTLS implementation in DC circuits and high-phase order transmission systems;
- Comparison of magnetic field with conventional conductors and evaluation of the effect on environment due to high currents.

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APPENDIX A

Test Bed Data

Table A.1 Generator records (bus 1 – 109)

Number of Bus	ID	Status	Set Volt	AGC	AVR	Min MW	Max MW	Min MVAr	Max MVAr
1	1	Closed	1.05	YES	YES	0	885	-342	480
2	1	Closed	1.05	YES	YES	0	750	-280	395
4	1	Closed	1.05	YES	YES	0	2415	-600	1050
8	1	Closed	1.05	YES	YES	150	950	-600	540
9	1	Closed	1.05	YES	YES	0	984	-600	700
11	1	Closed	1.05	YES	YES	0	750	-280	500
17	1	Closed	1.05	YES	YES	0	110	-42	50
23	1	Closed	1.05	YES	YES	0	560	-200	280
41	1	Closed	1.05	YES	YES	0	360	-110	258
46	1	Closed	1.05	YES	YES	0	639.6	-315	430.5
56	1	Closed	1.05	YES	YES	0	244.5	-85	150
57	1	Closed	1.05	YES	YES	0	153.5	-59	95
61	1	Closed	1.05	YES	YES	90	646	-283	401
62	1	Closed	1.07	YES	YES	0	1352	-310	800
63	1	Closed	1.07	YES	YES	0	1444	-310	800
64	1	Closed	1.07	YES	YES	0	1352	-310	800
65	1	Closed	1.05	YES	YES	0	862	-300	380
87	1	Closed	1.05	YES	YES	0	126	-19.5	47.5
94	1	Closed	1.05	YES	YES	0	58	-16	22
109	1	Closed	1.05	YES	YES	0	1382	-828	860

Table A.2 Generator records (bus 112 – 214)

Number of Bus	ID	Status	Set Volt	AGC	AVR	Min MW	Max MW	Min MVAr	Max MVAr
112	1	Closed	1.05	YES	YES	74	637	-84	269
123	1	Closed	1.05	YES	YES	200	976	-322	495
138	1	Closed	1.05	YES	YES	200	840	-240	430
146	1	Closed	1.05	YES	YES	0	75	-30	140
147	1	Closed	1.05	YES	YES	0	350	-140	200
177	1	Closed	1.05	YES	YES	0	212	-29	45
179	1	Closed	1.05	YES	YES	-12	30.4	-20	16
195	1	Closed	1.05	YES	YES	0	314	-82	92
196	1	Closed	1.05	YES	YES	0	330	-94	100
204	1	Closed	1	YES	YES	0	0	-9999	9999
205	1	Closed	1	YES	YES	0	0	-9999	9999
206	1	Closed	1	YES	YES	0	0	-9999	9999
207	1	Closed	1	YES	YES	0	0	-9999	9999
208	1	Closed	1	YES	YES	0	0	-9999	9999
209	1	Closed	1	YES	YES	0	0	-9999	9999
210	1	Closed	1	YES	YES	0	0	-9999	9999
211	1	Closed	1	YES	YES	0	0	-9999	9999
212	1	Closed	1	YES	YES	0	0	-9999	9999
213	1	Closed	1	YES	YES	0	0	-9999	9999
214	1	Closed	1	YES	YES	0	0	-9999	9999

Table A.3 Switched shunt records

Number of Bus	ID	Reg Bus Num	Status	Control Mode	Volt High	Volt Low	Nominal MVAr
11	1	11	Closed	Fixed	1.1	0.95	-90.00
26	1	26	Closed	Fixed	1.1	0.95	35.00
29	1	29	Closed	Fixed	1.1	0.95	300.00
31	1	31	Closed	Fixed	1.1	0.95	153.00
35	1	35	Closed	Fixed	1.1	0.95	43.20
55	1	55	Closed	Fixed	1.1	0.95	49.20
57	1	57	Closed	Fixed	1.1	0.95	15.60
76	1	77	Closed	Fixed	1.1	0.95	28.80
82	1	83	Closed	Fixed	1.1	0.95	27.00
92	1	93	Closed	Fixed	1.1	0.95	27.00
93	1	94	Closed	Fixed	1.1	0.95	40.00
112	1	113	Closed	Fixed	1.1	0.95	150.00
130	1	131	Closed	Fixed	1.1	0.95	40.00
137	1	138	Closed	Fixed	1.1	0.95	39.60
139	1	140	Closed	Fixed	1.1	0.95	33.10
157	1	158	Closed	Fixed	1.1	0.95	38.90
163	1	164	Closed	Fixed	1.1	0.95	200.00
186	1	187	Closed	Fixed	1.1	0.95	165.00
189	1	190	Closed	Fixed	1.1	0.95	240.00

Table A. 4 Transmission line records (lines 1-27)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
1	5	1	No	0.00218	0.04901	3.73739	2017.80
1	65	1	No	0.00074	0.01743	1.32274	1732.00
2	3	1	No	0.00177	0.04189	3.34000	1732.10
3	4	1	No	0.00077	0.01804	1.39842	2147.70
3	7	1	No	0.00098	0.02319	1.85366	2017.80
4	6	1	No	0.00241	0.05865	4.86560	2017.80
5	132	1	No	0.00003	0.00030	0.00000	1093.00
5	133	1	No	0.00003	0.00030	0.00000	1093.00
6	7	1	No	0.00081	0.01925	1.53854	2017.80
6	67	1	No	0.00040	0.00960	0.90380	2598.00
6	67	2	No	0.00040	0.00960	0.90380	2598.00
6	70	1	No	0.00000	0.00100	0.00000	1732.00
8	75	1	No	0.00020	0.00440	0.41670	2598.00
8	75	2	No	0.00020	0.00440	0.41670	2598.00
9	76	1	No	0.00000	0.00050	0.00000	3000.00
9	76	2	No	0.00000	0.00050	0.00000	3000.00
10	11	1	No	0.00855	0.08218	0.00000	687.20
10	11	2	No	0.00860	0.08270	0.00000	687.20
10	12	1	No	0.00361	0.06736	1.02994	597.60
10	13	1	No	0.00364	0.03474	0.53082	597.60
11	201	1	No	0.00030	0.00420	0.07150	1200.00
12	13	1	No	0.00340	0.03262	0.49913	597.60
14	164	1	No	0.00090	0.00970	0.01864	468.00
15	29	1	No	0.00330	0.02510	0.05860	370.90
15	31	1	No	0.00240	0.01870	0.04500	370.90
16	33	1	No	0.00800	0.07200	0.15120	435.00
16	61	1	No	0.00038	0.00281	0.00260	527.80

Table A.5 Transmission line records (lines 28-54)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
17	25	1	No	0.01180	0.06900	0.14400	280.90
18	25	1	No	0.00850	0.05400	0.09800	280.90
18	38	1	No	0.00770	0.04490	0.09000	211.00
19	26	1	No	0.00035	0.00143	0.31160	462.10
19	28	1	No	0.00020	0.00070	0.17000	518.00
19	52	1	No	0.00030	0.00100	0.06148	509.90
20	39	1	No	0.00190	0.01714	0.05932	720.00
20	113	1	No	0.00096	0.00832	0.03008	720.00
20	121	1	No	0.00161	0.01460	0.05006	720.30
21	159	1	No	0.00830	0.08790	0.16934	239.00
21	164	1	No	0.00840	0.08870	0.17078	468.00
22	36	1	No	0.00090	0.00930	0.03660	637.40
22	40	1	No	0.00085	0.00837	0.00000	733.00
22	112	1	No	0.00081	0.00781	0.02100	435.00
24	52	1	No	0.00100	0.01010	0.22772	457.00
24	112	1	No	0.00040	0.00400	0.00720	457.00
26	29	1	No	0.00210	0.01680	0.03400	313.00
26	46	1	No	0.00135	0.00746	0.01031	750.00
27	30	1	No	0.00050	0.00501	0.01877	733.00
27	31	1	No	0.00158	0.01515	0.03154	437.00
27	35	1	No	0.00089	0.00887	0.02000	457.70
28	35	1	No	0.00053	0.00220	0.53400	324.70
29	31	1	No	0.00480	0.03720	0.07200	370.90
29	44	1	No	0.00388	0.02936	0.06164	309.10
30	31	1	No	0.00073	0.00721	0.02591	733.00
31	121	1	No	0.00015	0.00130	0.00000	286.80
31	121	2	No	0.00015	0.00130	0.00000	286.80
31	170	1	No	0.00001	0.00030	0.00000	637.00

Table A.6 Transmission line records (lines 55-81)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
32	48	1	No	0.01370	0.09600	0.16740	334.60
32	51	1	No	0.00000	0.00030	0.00000	268.10
32	189	1	No	0.01580	0.10970	0.19112	259.00
33	37	1	No	0.00666	0.04868	0.09270	286.80
34	37	1	No	0.00582	0.04254	0.08200	286.80
34	61	1	No	0.00266	0.01981	0.04460	796.70
34	129	1	No	0.00483	0.02824	0.06230	1164.80
34	175	1	No	0.00000	0.00200	0.00000	200.00
36	39	1	No	0.00080	0.00900	0.03540	720.20
38	42	1	No	0.00361	0.02105	0.04218	211.00
39	49	1	No	0.00133	0.01054	0.01916	374.00
39	112	1	No	0.00213	0.01867	0.06788	797.00
39	164	1	No	0.00397	0.03480	0.12662	637.40
39	170	1	No	0.00272	0.02740	0.13488	733.00
40	46	1	No	0.00197	0.01540	0.05855	717.00
40	131	1	No	0.00074	0.00580	0.01937	1195.00
41	131	1	No	0.00182	0.01419	0.03918	1195.00
42	50	1	No	0.00420	0.02600	0.04890	306.00
43	45	1	No	0.00090	0.00860	0.01880	437.40
44	118	1	No	0.00000	0.00030	0.00000	804.70
44	129	1	No	0.00083	0.00470	0.01005	1170.00
45	164	1	No	0.00710	0.06470	0.14380	437.40
47	113	1	No	0.00000	0.00030	0.00000	750.00
48	170	1	No	0.00300	0.02130	0.03710	334.60
49	179	1	No	0.00067	0.00526	0.00956	374.00
50	51	1	No	0.00000	0.00030	0.00000	796.70
53	60	1	No	0.02710	0.12160	0.01664	47.80
53	146	1	No	0.01530	0.09430	0.01314	120.00

Table A.7 Transmission line records (lines 82-108)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
53	183	1	No	0.03800	0.23370	0.03264	120.00
54	82	1	No	0.00000	0.00030	0.00000	142.00
56	57	1	No	0.00010	0.00030	0.00000	598.00
56	152	1	No	0.01060	0.06490	0.00904	167.00
56	168	1	No	0.01710	0.10530	0.01470	120.00
56	180	1	No	0.00270	0.01660	0.00232	120.00
57	58	1	No	0.03091	0.25063	0.02980	159.30
57	163	1	No	0.03480	0.14890	0.01976	100.00
57	174	1	No	0.01540	0.09480	0.01322	120.00
58	168	1	No	0.02960	0.12340	0.01630	145.40
59	160	1	No	0.01370	0.03790	0.00448	80.10
59	168	1	No	0.08820	0.24420	0.02622	80.10
65	72	1	No	0.00176	0.04189	3.32630	1732.00
66	73	1	No	0.00026	0.00382	0.41947	1732.00
66	75	1	No	0.00048	0.01091	1.06576	1732.00
67	74	1	No	0.00034	0.00724	0.68725	1732.10
67	76	1	No	0.00003	0.00069	0.64820	1732.00
67	76	2	No	0.00003	0.00067	0.62620	2598.00
67	76	3	No	0.00003	0.00071	0.53580	1299.00
68	70	1	No	0.00000	0.00010	0.00000	1238.00
69	70	1	No	0.00000	0.00010	0.00000	1238.00
71	158	1	No	0.00182	0.05144	4.89200	1238.00
72	73	1	No	0.00046	0.00874	0.70448	1732.00
75	76	1	No	0.00020	0.00428	0.40122	1732.00
76	77	1	No	0.00000	0.00050	0.00000	3000.00
76	78	1	No	0.00020	0.00550	0.51350	3000.00
76	79	1	No	0.00000	0.00050	0.00000	3000.00
80	81	1	No	0.00135	0.00236	0.00014	73.70

Table A.8 Transmission line records (lines 109-135)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
81	82	1	No	0.06184	0.18458	0.01192	119.50
81	86	1	No	0.00056	0.00168	0.00011	95.20
82	160	1	No	0.02706	0.08076	0.00521	139.40
83	107	1	No	0.00030	0.00130	0.00020	83.60
84	87	1	No	0.02469	0.11702	0.01640	159.30
84	92	1	No	0.03040	0.14536	0.01996	119.50
84	108	1	No	0.00901	0.01407	0.00144	39.80
85	87	1	No	0.01739	0.09977	0.01360	181.20
85	94	1	No	0.00988	0.04722	0.00648	159.30
85	103	1	No	0.01327	0.03312	0.00762	167.30
85	104	1	No	0.03472	0.06072	0.00714	73.70
86	89	1	No	0.01742	0.05146	0.00337	95.20
86	146	1	No	0.01319	0.11675	0.01592	123.50
86	146	1	No	0.11333	0.39946	0.05064	123.50
87	94	1	No	0.01282	0.06033	0.00856	159.30
88	89	1	No	0.00004	0.00017	0.00000	22.90
89	93	1	No	0.01617	0.47870	0.00313	119.50
90	93	1	No	0.00178	0.00587	0.00040	119.50
90	98	1	No	0.00321	0.01013	0.00067	119.50
91	96	1	No	0.00549	0.01724	0.00234	139.40
91	97	1	No	0.01218	0.04139	0.00732	119.50
91	107	1	No	0.00160	0.00730	0.00110	161.30
92	96	1	No	0.00711	0.03321	0.00468	119.50
92	106	1	No	0.00117	0.00222	0.00026	83.60
95	102	1	No	0.00290	0.01385	0.00190	161.30
95	105	1	No	0.00430	0.02030	0.00290	119.50
96	102	1	No	0.01638	0.07814	0.01080	172.10
97	101	1	No	0.01000	0.03120	0.00630	172.10

Table A.9 Transmission line records (lines 136-162)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
98	105	1	No	0.01422	0.06811	0.00466	164.30
99	106	1	No	0.00119	0.00225	0.00013	39.80
100	102	1	No	0.00046	0.00292	0.00094	328.60
101	105	1	No	0.00888	0.02131	0.00964	164.30
103	105	1	No	0.03392	0.10392	0.02028	181.20
106	107	1	No	0.00040	0.00200	0.00030	164.30
110	176	1	No	0.00000	0.00050	0.00000	120.00
111	174	1	No	0.00000	0.00050	0.00000	145.40
112	113	1	No	0.00120	0.00988	0.04042	725.00
112	128	1	No	0.00141	0.01238	0.04502	725.00
114	118	1	No	0.00136	0.00845	0.06192	725.00
114	119	1	No	0.00110	0.00671	0.05070	725.00
115	118	1	No	0.00101	0.00877	0.03218	637.40
115	120	1	No	0.00067	0.00584	0.02142	637.40
115	121	1	No	0.00610	0.03608	0.07322	363.00
115	121	2	No	0.00611	0.03614	0.07334	363.00
115	127	1	No	0.00031	0.00185	0.00374	358.50
115	127	2	No	0.00031	0.00185	0.00374	358.50
116	118	1	No	0.00082	0.00716	0.02604	637.00
116	123	1	No	0.00080	0.00730	0.02660	598.00
117	125	1	No	0.00948	0.05145	0.10522	458.00
117	126	1	No	0.00237	0.01409	0.02852	363.00
117	126	2	No	0.00237	0.01409	0.02852	363.00
118	120	1	No	0.00123	0.01072	0.03912	796.70
118	124	1	No	0.00314	0.01778	0.04698	450.10
119	131	1	No	0.00109	0.00941	0.03512	637.00
119	164	1	No	0.00249	0.02143	0.08008	498.00
120	121	1	No	0.00385	0.02510	0.17054	717.00

Table A.10 Transmission line records (lines 163-189)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
121	170	1	No	0.00003	0.00030	0.00000	637.00
121	170	2	No	0.00002	0.00030	0.00000	637.00
122	126	1	No	0.00187	0.01103	0.02236	362.50
122	190	1	No	0.00000	0.00050	0.00000	399.00
122	190	2	No	0.00000	0.00050	0.00000	399.00
123	124	1	No	0.00229	0.01096	0.08382	788.00
123	126	1	No	0.00148	0.01296	0.04742	363.00
123	130	1	No	0.00315	0.01386	0.01562	788.00
128	131	1	No	0.00050	0.00435	0.01582	725.00
131	164	1	No	0.00157	0.01274	0.04801	894.00
134	138	1	No	0.00101	0.01057	0.19400	755.00
135	138	1	No	0.00511	0.05386	0.96200	925.00
135	142	1	No	0.00407	0.04244	0.77763	925.00
135	151	1	No	0.00002	0.00021	0.00379	818.70
136	138	1	No	0.00498	0.05195	0.95080	925.00
136	138	2	No	0.00491	0.05135	0.94180	925.00
137	139	1	No	0.00063	0.00663	0.12300	925.00
137	141	1	No	0.00817	0.08550	1.60340	925.00
138	140	1	No	0.00508	0.04856	1.07680	717.00
138	140	2	No	0.00592	0.06168	1.13960	717.00
139	142	1	No	0.00185	0.01929	0.35347	925.00
139	149	1	No	0.00108	0.01185	0.19640	818.70
143	144	1	No	0.04330	0.23308	0.00000	9997.00
143	145	1	No	0.01090	0.06078	0.00000	9997.00
143	214	1	No	0.00000	0.11142	0.00000	9997.00
144	145	1	No	0.01340	0.07974	0.00000	9997.00
144	213	1	No	0.00000	0.10983	0.00000	9997.00
145	212	1	No	0.00000	0.04913	0.00000	9997.00

Table A.11 Transmission line records (lines 190-216)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
146	211	1	No	0.00000	0.12131	0.00000	9997.00
147	148	1	No	0.02090	0.12609	0.00000	9997.00
147	150	1	No	0.01550	0.14199	0.00000	9997.00
147	153	1	No	0.00330	0.02919	0.06369	438.20
148	152	1	No	0.15360	0.42814	0.00000	9997.00
152	171	1	No	0.02140	0.13140	0.00000	9997.00
154	155	1	No	0.00290	0.02317	0.00000	9997.00
154	155	1	No	0.00000	0.00760	0.00000	1593.00
154	156	1	No	0.01370	0.09500	0.16600	319.00
154	210	1	No	0.00000	0.04921	0.00000	9997.00
155	156	1	No	0.02210	0.19372	0.00000	9997.00
155	159	1	No	0.02280	0.16653	0.00000	9997.00
155	177	1	No	0.00457	0.03292	0.06020	358.00
155	209	1	No	0.00000	0.01000	0.00000	9997.00
156	159	1	No	0.00330	0.02916	0.00000	9997.00
156	185	1	No	0.00830	0.06278	0.00000	9997.00
156	208	1	No	0.00000	0.01144	0.00000	9997.00
157	186	1	No	0.00307	0.04261	0.69365	1171.20
159	178	1	No	0.00620	0.06590	0.12680	239.00
159	207	1	No	0.00000	0.05233	0.00000	9997.00
160	172	1	No	0.01040	0.06380	0.00890	120.00
160	173	1	No	0.01670	0.04690	0.00568	135.00
160	191	1	No	0.00000	0.00050	0.00000	135.00
161	181	1	No	0.00740	0.05120	0.08892	319.00
161	187	1	No	0.00200	0.01510	0.03030	451.00
161	187	2	No	0.00200	0.01510	0.03030	451.00
162	171	1	No	0.00900	0.05550	0.00774	120.00

Table A.12 Transmission line records (lines 217-243)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
162	183	1	No	0.00950	0.05820	0.00812	120.00
163	184	1	No	0.03640	0.10210	0.01240	120.00
164	167	1	No	0.00800	0.06350	0.10920	451.00
164	169	1	No	0.00430	0.03230	0.06678	319.00
164	188	1	No	0.00290	0.03020	0.05792	335.00
165	186	1	No	0.00563	0.07809	1.27136	1171.20
167	169	1	No	0.01820	0.11740	0.01510	120.00
167	175	1	No	0.02200	0.11840	0.01470	102.00
167	187	1	No	0.00740	0.05810	0.11940	451.00
168	171	1	No	0.04590	0.14990	0.01814	120.00
168	192	1	No	0.00000	0.00050	0.00000	145.40
170	190	1	No	0.00420	0.03190	0.06480	438.00
170	190	2	No	0.00420	0.03190	0.06480	438.00
172	173	1	No	0.00840	0.05160	0.00720	120.00
172	176	1	No	0.00840	0.05160	0.00720	120.00
172	180	1	No	0.03100	0.19070	0.00000	9997.00
174	176	1	No	0.00830	0.05100	0.00712	120.00
175	182	1	No	0.00868	0.09030	0.01080	225.00
178	188	1	No	0.00770	0.00626	0.20440	334.00
181	190	1	No	0.00170	0.01150	0.01990	438.00
185	189	1	No	0.00475	0.03299	0.05726	335.00
185	206	1	No	0.00000	0.05620	0.00000	9997.00
187	205	1	No	0.00000	0.28985	0.00000	9997.00
193	196	1	No	0.00570	0.06500	1.00700	1100.00
193	196	2	No	0.00550	0.06540	1.00700	1100.00
193	198	1	No	0.00500	0.05950	0.91620	896.00
193	198	2	No	0.00490	0.05980	0.91080	1195.10

Table A.13 Transmission line records (lines 244-248)

From Number	To Number	Circuit	Xfrmr	*R*	*X*	*B*	Lim A MVA
194	202	1	No	0.00327	0.01100	0.06906	440.00
196	204	1	No	0.00000	0.02776	0.00000	9997.00
197	200	1	No	0.01620	0.16110	0.29490	440.00
197	203	1	No	0.00229	0.02277	0.04144	398.40
202	203	1	No	0.00660	0.06578	0.11970	398.40

Table A.14 Transformer records (transformer 1 – 27)

From Number	To Number	Circuit	Xfrmr	R	X	B	Lim A MVA	Tap Ratio
1	10	1	Yes	0.00040	0.03312	0	1000.0000	0.97951
2	11	1	Yes	0.00018	0.01060	0	840.0000	1.02375
5	55	1	Yes	0.00057	0.04562	0	725.0000	1.02435
5	56	1	Yes	0.00055	0.04589	0	725.0000	1.02435
6	39	1	Yes	0.00029	0.02534	0	4482.0000	0.98438
6	205	1	Yes	0.00003	0.01261	0	672.0000	1.05000
7	41	1	Yes	0.00093	0.08253	0	672.0000	0.99590
8	44	1	Yes	0.00040	0.03150	0	560.0000	1.05000
10	17	1	Yes	0.00111	0.04225	0	203.0000	1.00000
11	23	1	Yes	0.00057	0.02771	0	1250.0000	1.00000
12	31	1	Yes	0.00074	0.04122	0	1875.0000	0.97500
32	54	1	Yes	0.00658	0.16986	0	166.6000	0.97500
33	55	1	Yes	0.00107	0.03440	0	200.0000	1.00000
33	56	1	Yes	0.00085	0.03516	0	200.0000	1.00000
63	128	1	Yes	0.00018	0.01456	0	672.0000	1.02375
64	203	1	Yes	0.00006	0.00298	0	1233.0000	1.02380
64	204	1	Yes	0.00056	0.01153	0	1233.0000	1.02380
65	60	1	Yes	0.00011	0.00973	0	1533.0000	1.07763
65	61	1	Yes	0.00011	0.00964	0	1533.0000	1.07763
65	62	1	Yes	0.00011	0.00977	0	1533.0000	1.07763
69	66	1	Yes	0.00000	0.02000	0	650.0000	1.00000
69	67	1	Yes	0.00000	0.02000	0	650.0000	1.00000
70	202	1	Yes	0.00005	0.01308	0	1233.0000	1.02380
71	200	1	Yes	0.00056	0.01153	0	598.0000	1.05000
71	201	1	Yes	0.00056	0.01153	0	598.0000	1.05000
72	197	1	Yes	0.00015	0.01717	0	598.0000	1.05000
72	198	1	Yes	0.00015	0.01717	0	598.0000	1.05000

Table A.15 Transformer records (transformer 28-54)

From Number	To Number	Circuit	Xfrmr	R	X	B	Lim A MVA	Tap Ratio
72	199	1	Yes	0.00015	0.01717	0	598.0000	1.05000
75	103	1	Yes	0.00000	0.00280	0	1500.0000	1.05000
111	81	1	Yes	0.00000	0.08287	0	404.0000	1.02500
112	203	1	Yes	0.00006	0.00958	0	1233.0000	1.00000
112	204	1	Yes	0.00055	0.00012	0	1233.0000	1.00000
119	96	1	Yes	0.00000	0.03776	0	300.0000	1.00000
119	97	1	Yes	0.00000	0.03801	0	300.0000	1.00000
119	202	1	Yes	0.00006	0.00183	0	1233.0000	1.00000
124	200	1	Yes	0.00055	0.00012	0	598.0000	1.00000
124	201	1	Yes	0.00055	0.00012	0	598.0000	1.00000
125	197	1	Yes	0.00015	0.00553	0	598.0000	1.00000
125	198	1	Yes	0.00015	0.00553	0	598.0000	1.00000
125	199	1	Yes	0.00015	0.00553	0	598.0000	1.00000
131	196	1	Yes	0.00013	0.01194	0	672.0000	0.99526
133	195	1	Yes	0.00014	0.01249	0	672.0000	0.99526
134	139	1	Yes	0.00015	0.01614	0	672.0000	1.00000
135	205	1	Yes	0.00020	0.00011	0	672.0000	1.00000
136	147	1	Yes	0.00000	0.02827	0	375.0000	1.00000
137	196	1	Yes	0.00013	0.02844	0	672.0000	1.00000
138	126	1	Yes	0.00039	0.02550	0	672.0000	1.00000
138	127	1	Yes	0.00039	0.02550	0	672.0000	1.00000
139	195	1	Yes	0.00041	0.02927	0	672.0000	1.00000
141	140	1	Yes	0.00000	0.18200	0	200.0000	1.00000
143	142	1	Yes	0.00000	0.04433	0	150.0000	1.02500
145	144	1	Yes	0.00000	0.04444	0	150.0000	0.98040
151	148	1	Yes	0.00004	0.01420	0	600.0000	0.97510
152	148	1	Yes	0.00000	0.01514	0	1300.0000	1.07520

Table A.16 Transformer records (transformer 55-64)

From Number	To Number	Circuit	Xfrmr	R	X	B	Lim A MVA	Tap Ratio
155	154	1	Yes	0.00000	0.06000	0	500.0000	0.98040
158	159	1	Yes	0.00004	0.01420	0	600.0000	1.00000
159	157	1	Yes	0.00000	0.01586	0	500.0000	1.00000
173	175	1	Yes	0.00000	0.03000	0	167.0000	1.02500
177	176	1	Yes	0.00005	0.01795	0	650.0000	1.00000
185	186	1	Yes	0.00054	0.02695	0	350.0000	1.00000
187	186	1	Yes	0.00080	0.04540	0	700.0000	1.00000
189	163	1	Yes	0.00017	0.04872	0	1800.0000	0.97500
191	190	1	Yes	0.00100	0.04220	0	400.0000	1.00000
192	191	1	Yes	0.00000	0.02333	0	300.0000	1.00000

Table A.17 Load records (bus 2 – 60)

Number of Bus	ID	Status	S MW	S MVar
2	1	Closed	257.12	-4.84
3	1	Closed	505.80	-5.41
4	1	Closed	594.49	-27.79
10	1	Closed	72.72	8.28
11	1	Closed	13.20	0.00
13	1	Closed	39.36	0.00
14	1	Closed	36.72	7.80
15	1	Closed	201.00	56.94
16	1	Closed	40.44	6.06
17	1	Closed	44.70	5.34
18	1	Closed	129.36	14.22
19	1	Closed	154.98	70.62
20	1	Closed	295.20	86.04
21	1	Closed	19.62	31.68
22	1	Closed	186.00	68.40
23	1	Closed	14.04	1.98
23	2	Closed	65.63	-14.87
24	1	Closed	29.28	3.00
25	1	Closed	0.72	0.30
26	1	Closed	82.50	12.36
27	1	Closed	124.62	35.88
28	1	Closed	83.64	36.90
29	1	Closed	19.27	14.80
30	1	Closed	91.50	24.84
31	1	Closed	260.40	81.60
32	1	Closed	81.24	3.66
34	1	Closed	21.66	4.26
35	1	Closed	201.60	77.52
36	1	Closed	113.76	27.54
37	1	Closed	9.48	0.00
38	1	Closed	68.22	21.42
39	1	Closed	125.76	27.66
40	1	Closed	54.00	13.20
42	1	Closed	27.30	0.00
43	1	Closed	26.70	5.16
47	1	Closed	122.52	3.18
49	1	Closed	27.42	8.22
53	1	Closed	28.14	8.40
54	1	Closed	4.98	1.62
55	1	Closed	35.17	14.76
57	1	Closed	0.84	0.00
58	1	Closed	14.40	7.74

Table A.18 Bus records (bus 62 – 144)

Number of Bus	ID	Status	S MW	S MVar
62	1	Closed	39.00	29.28
63	1	Closed	39.00	29.28
64	1	Closed	39.00	29.28
65	1	Closed	19.56	2.82
67	1	Closed	851.11	138.96
76	1	Closed	500.40	46.20
80	1	Closed	13.44	6.60
83	1	Closed	12.66	5.22
84	1	Closed	0.12	0.06
86	1	Closed	14.16	8.22
88	1	Closed	2.58	0.30
90	1	Closed	18.90	8.22
91	1	Closed	1.32	0.48
92	1	Closed	10.08	6.48
93	1	Closed	7.56	4.86
95	1	Closed	0.12	0.06
96	1	Closed	13.38	5.40
97	1	Closed	3.60	1.44
98	1	Closed	5.52	3.78
99	1	Closed	1.38	0.54
103	1	Closed	17.16	0.00
105	1	Closed	1.14	0.00
110	1	Closed	12.18	7.50
111	1	Closed	9.00	5.58
112	1	Closed	306.90	23.22
113	1	Closed	158.46	0.78
114	1	Closed	216.30	6.54
115	1	Closed	115.39	12.66
116	1	Closed	294.18	-1.45
118	1	Closed	75.24	9.26
119	1	Closed	214.98	4.93
120	1	Closed	243.72	2.34
122	1	Closed	227.16	-2.60
124	1	Closed	147.06	-14.41
126	1	Closed	434.76	-27.97
127	1	Closed	203.04	14.28
128	1	Closed	188.52	0.00
129	1	Closed	130.68	5.22
130	1	Closed	70.32	0.00
135	1	Closed	121.48	55.40
135	2	Closed	82.16	-37.70
136	1	Closed	-321.92	45.07
138	1	Closed	243.82	19.13

Table A.19 Load records (bus 145 – 216)

Number of Bus	ID	Status	S MW	S MVar
145	1	Closed	366.48	4.48
146	1	Closed	-9.84	13.50
147	1	Closed	55.48	-1.18
148	1	Closed	44.69	0.38
150	1	Closed	24.24	-1.09
152	1	Closed	40.65	2.63
154	1	Closed	-54.64	10.72
154	2	Closed	279.17	33.39
155	1	Closed	206.87	-193.54
155	2	Closed	-381.63	216.25
156	1	Closed	-107.18	-3.46
158	1	Closed	11.18	199.80
159	1	Closed	9.52	-2.66
159	2	Closed	85.31	24.39
160	1	Closed	26.34	8.70
167	1	Closed	11.58	4.27
171	1	Closed	4.90	-0.97
172	1	Closed	9.95	1.67
173	1	Closed	1.38	0.48
175	1	Closed	14.41	1.90
178	1	Closed	10.44	0.00
180	1	Closed	4.40	-0.72
183	1	Closed	68.35	11.87
184	1	Closed	5.40	1.80
185	1	Closed	-18.33	18.05
187	1	Closed	-29.22	-0.34
188	1	Closed	17.88	0.00
189	1	Closed	11.88	-1.32
191	1	Closed	7.38	2.76
192	1	Closed	21.06	6.90
195	1	Closed	-49.33	-1.54
195	2	Closed	15.00	4.98
196	1	Closed	-229.88	40.92
197	1	Closed	18.66	6.18
199	1	Closed	13.22	3.38
199	2	Closed	-6.64	1.22
200	1	Closed	-78.62	15.32
201	1	Closed	-200.40	13.80
203	1	Closed	16.44	5.40
216	1	Closed	0.00	-4.99