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Economic analysis of transmission enhancement through merchant projects

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ABSTRACT

The lack of economic incentives and uncertainties in recovering the cost of a merchant / economic transmission project is an area of great concern as aging and heavy loading conditions limit the capability of the U.S. transmission networks. Merchant transmission projects are envisioned as market based solutions to enhance the power grid and to import cheaper energy from power suppliers in other areas. However, due to uncertainties in the electric energy market, market based cost recovery mechanisms have not been successful in guaranteeing a full recovery of the investment. As a result, few merchant projects have been built. This dissertation presents a comprehensive analysis of merchant transmission projects and the required economic incentives that are necessary to enhance the power grid.

The concept of perpetual options theory is initially introduced to analyze merchant transmission investment through an approved rate. Since the electric usages and the associated revenue are stochastic in nature, applying the perpetual options theory allows an investor to determine the most opportunistic time to start a transmission project and obtain the maximum revenue returns or let the option expire when the economic incentive is not sufficient. In today's environment, this decision approach is more appropriate since it provides transmission investors a better evaluation of its return on investment and an exit strategy for an investment. The probability of not recovering the capital investment associated with an exercise of the option to build is calculated using Kolmogorov forward equation. The risk of an exercise is needed for decision making of the investment and for assessing the incentive needed to encourage transmission investment.

A market based transmission rate is designed as an additional incentive for merchant projects. The new rate design provides additional revenues to transmission developers in order to attract the transmission investment. The rate takes into consideration the revenue requirement by the developer and benefits to transmission customers. Finally, a conceptual framework to analyze the strategic interaction between power plant investment and transmission line investment is proposed. The model, which is based on game theory, helps to evaluate different market incentives and the impact of generator's decision on transmission enhancement projects.

CHAPTER 1. INTRODUCTION

1.1 Motivation and Objectives

The lack of economic incentives and uncertainties in recovering the cost of a merchant / economic transmission project is an area of great concern as the aging transmission infrastructure and heavy loading conditions of the U.S. transmission grids are worsened over the last decade. The U.S. government, industry, and research community are taking steps to address the issue of the lack of investment to enhance the transmission grids. An example of the efforts is that the 2005 Energy Policy Act directed a commission to develop an incentive-based rate for transmission investments. The final rule of the commission is expected to generate the much needed incentives to invest in transmission systems that will improve the system reliability and competitiveness of the energy markets. The final rule consists of a series of incentives that allow investors to "select and justify the package of incentives needed to support new investment" [1]. Other important actions have been pointed out by the North American Electric Reliability Corporation (NERC) in a recent report [2]. The need to "reduce regulatory barriers and encourage investment in transmission" by the Federal and State regulators and the need to "engage in long-term, robust, and comprehensive regional planning for transmission" are two important issues addressed by the report.

In general, there are two types of transmission projects: reliability and economic projects. Reliability projects are determined by transmission planning of the regional transmission organizations (RTOs) for meeting the regional reliability criteria in a specific planning year. These are projects that regional transmission owners (TOs) are obligated to build and have a well-defined completion date as determined by the planning year in which they are identified. Since meeting reliability criteria is a regulatory requirement, TOs have been building these reliability projects and recovering the investment from the approved transmission rate.

On the contrary, there is currently no obligation for a TO to build an economic project to import cheaper energy to serve the load serving entities (LSE) loads. Since the load may not be affiliated with the TO, the energy savings to the load may not be realized by the TO. These projects would be merchant transmission projects, and the cost recovery, at least in theory, would be from those who benefit from the cheaper energy. Hence, the transmission investment decision is based primarily on the perceived energy savings of the LSE, and the payment from LSEs to the project developer is likely a negotiated contract instead of a regulatory approved rate. Note that it is difficult to provide an accurate revenue forecast due to high volatility of energy prices. Furthermore, in a competitive environment, loads can change their suppliers. As a result, LSEs are reluctant to commit to a long-term transmission investment.

Merchant transmission projects can be built at any time, depending on the economic conditions. A transmission investor (TI) could determine the most opportunistic time to invest by optimizing the transmission revenue stream over the life of the project. The TI can also cancel the project if the project can no longer be justified. The TI can come forward with the intention to build and choose when to build if the projected rate-based revenue is favorable. Otherwise, the investor can withdraw the intention without incurring a penalty.

It was envisioned that merchant projects or transmission investments based on financial transmission rights (FTRs) are sufficient incentives for transmission investments.

Early work [3]-[4] showed how financial instruments can be implemented to support the required transmission expansion. It has been noted by [4] that, under a strong set of assumptions, transmission rights are able to fully recover the investment cost. However, due to market imperfection (e.g., market power, strategic behavior), and the fact that power flow follows physical laws and hence is not fully controllable, transmission costs are not fully recovered by financial instruments [7]. Specifically, marginal pricing fails to recover transmission costs. Since the investment cost may not be fully recovered, few merchant transmission projects have been built. Therefore, new incentives mechanisms are necessary to promote merchant investments, and hence have a competitive electricity market.

The purpose of this research is to develop analytical methods for merchant transmission investments in order to determine the incentive mechanisms that are needed for enhancement of the transmission grid. To address this issue, merchant investments are analyzed from two different perspectives, namely:

1. A novel investment criterion is developed based on the option theory. The criterion guarantees the most convenient investment time and the required economic incentives for a merchant project. In addition, since neither FERC nor the State commission has endorsed any cost recovery method at this time, the criterion and a risk assessment tool provides an exit strategy (abandon the option to invest) when the cost mechanism does not provided sufficient incentives.
2. The second approach builds on the first approach and designs a transmission rate as an additional cost recovery mechanism to increase the revenues and provide the needed incentives for merchant projects. The transmission rate is designed based on market considerations rather than the traditional cost recovery method. The rate takes

into account transmission customers' interest, and hence incorporates a tradeoff mechanism between transmission developers' desire to increase profits and the benefits to customers.

1.2 State of the Art of Merchant Transmission Economics

Merchant transmission projects were intended as a market-driven solution to keep the system reliable and competitive [4]-[5]-[8]-[9] . However, as pointed out in [5]-[10], returns to scale, lumpiness, and strategic behaviors by different market participants led to an insufficient level of merchant project investment. Moreover, due to the fact that power flow follows physical laws and hence is not fully controllable, financial instruments also fail to recover the cost of enhancement [11]-[12]-[13]. Specifically, reference [7] shows how marginal pricing fails to recover transmission costs. A summary of obstacles facing merchant transmission investment is reported in [14]-[15]. Since the cost can not be fully recovered, few merchant projects have been built [1]-[16]-[70].

Additional economic incentives under consideration are in the areas of cost allocation [17]-[62], allocation of annual revenue rights/financial transmission rights [18], market signals for grid expansion [32]-[33], and market architecture. However, there is not a consensus about the proper economic incentives.

The previous work approaches transmission investment from an institutional point of view, i.e., they focus on market design criteria that must incentivize transmission investment. Nevertheless, little research has been conducted on transmission investment from an investor's point of view.

Capital budgeting is a research field that is concerned with the optimal allocation of capital resources. There exists is a vast literature on capital budgeting techniques [26]-[30]. For instance, [29] has become a classical reference for capital budgeting technique. From an investor's point of view, merchant transmission projects must be analyzed using those procedures. Discounted cash flow or decision trees are capital budgeting techniques commonly used by investors to evaluate various projects and allocate resources on a long-term basis. Additionally, Monte Carlo simulation is used to incorporate future uncertainties and quantify the associated risks of investment [30]-[71].

Merchant projects offer a variety of challenges that do not allow a straightforward application of capital budgeting techniques. Specifically, uncertainties from the electricity market, e.g., generator bids, contingencies, other participants' decisions, are difficult to model and therefore hard to incorporate into the model [51]-[64]-[67].

Real options have emerged as a new budgeting tool that has become a well established technique on investment assessment [27]-[30]-[22]-[23]. Real options take into account uncertainties from a variety of sources in order to evaluate a potential investment. Option theory has been applied to a transmission expansion project due to demand uncertainty [24] and, in [25], an overview of transmission expansion planning using real options is presented. However, the option to invest is not analyzed as an instrument of profit. Chapter 3 develops a technique based on option theory as a profit-seeking instrument.

Transmission tariff is a widely cost recover mechanism used by regulated industry [68]-[4]. Under a vertically integrated structure, power utilities recover the capital investment, operational and maintenance cost through a regulated rate [4]-[56]-[63]-[64]. Power utilities in North America still uses transmission rates to recover the required cost incurred in providing the service. In [56], a survey of transmission tariffs in North America is presented. According to the review, there exists a diversity of transmission design mechanisms. For instance, transmission owners at PJM pay for transmission enhancements and recover the cost through FERC-approved transmission rate; whereas each transmission owner in California can recover the investment via access charges and congestion charges. As a consequence, there is not a unified transmission rate design.

According to economic theory, a transmission rate should send the correct economical signal to achieve the most efficient use of the transmission grid [59]-[60]-[61]-[63]-[68]. It is note that LMPs provide the appropriate short term signals to use the grid but not the long term signals for the grid enhancement. Due to this lack of signals, various transmission rate mechanisms have been proposed. In [59]-[57], for instance, guidelines on tariff setting are provided.

1.3 Contributions of this Dissertation

Analysis of the merchant transmission investment has emerged as a new area of research in electric energy economics due to the increasing need for enhancement of the transmission networks in the U.S. Over the last decades, the load on the electric power grids has grown steadily that is accompanied by a healthy increase in generation capacities through construction of new power plants. However, the transmission network has not been enhanced in any significant manner. This lack of transmission enhancement has led to network congestions and heady loading conditions.

Reliability driven transmission enhancement is a crucial element in enhancing the transmission grids. However, merchant transmission enhancement is also important for upgrading the capabilities of the transmission grids. As pointed out earlier, merchant transmission projects are motivated by the desire to bring cheaper energy from an area to another. Therefore, the economic analysis is needed to establish the necessary incentives that encourage investors to pursue these projects. The research in this dissertation is to develop new concepts and techniques for the merchant transmission investment. Specifically, it is believed that the contributions of this dissertation include:

1. An investment evaluation technique based on real options for merchant transmission projects

   The technique provides an investment criterion that optimizes the random revenues derived from the project. The criterion also considers the fact that transmission investor is not obligated to build a merchant project. The analysis tool provides a new index for decision analysis, i.e., the waiting time that is not available from traditional investment techniques such as net present value or decision trees.

2. A risk assessment evaluation tool that builds on the fact that revenues are stochastic and there is not a firm date to initiate the construction of a merchant project

   The assessment method provides a closed-form solution of the probability density function of future revenues. The closed-form offers an accurate estimate of the probability of not recovering the capital investment if the option to build a merchant project is exercised.

3. A new market-based transmission rate

   Transmission rate is often established based on the cost requirement rather than market incentives. The new rate design provides additional revenues to transmission developers in order to encourage the needed transmission investment. The rate takes into consideration the revenues requirement by the developer and the benefits to transmission customers.

4. A conceptual framework to analyze the strategic iteration between power plant investment and transmission investment

   The framework introduces a theoretical structure to address the complex iterations between generation and transmission investments. The model, which is based on game theory, helps to evaluate different market incentives and generator's decision on transmission enhancements.

1.4 Thesis Organization

This dissertation is organized as follows: Chapter 2 provides a formulation of the transmission investment decision problem based on the options theory. The optimal investment strategy for merchant transmission projects is developed. Numerical results are reported at the end of the chapter. Chapter 3 extends the optimal investment criterion with a risk assessment tool. The probability of not recovering the capital investment before reaching the optimal investment criterion is developed using Kolmogorov equations. Numerical results demonstrate the practical applications of the proposed assessment tool. The comprehensive analysis of merchant investments in this research establishes new mechanisms to conduct a tradeoff between transmission customers' interest and transmission investors desire to maximize profits. Chapter 4 develops a market – based transmission rate that can be used to reconcile the different interests. The chapter also provides a numerical example in order to illustrate the applicability of the proposed technique. Chapter 5 describes a theoretical framework to incorporate others' decisions in the transmission investment analysis. A simultaneous game is designed in order to assess the impact of strategic interactions. Finally, the conclusions are stated in Chapter 6.

CHAPTER 2. DECISION ANALYSIS OF MERCHANT TRANSMISSION INVESTMENT BY PERPETUAL OPTIONS THEORY

2.1 Problem Formulation

Consider a power market where merchant transmission projects are already identified by a Transmission Investor (TI). The proposed perpetual option formulation provides an investor with the option, but not the obligation, to build any or all of these new merchant projects at any time without a firm commitment date or an expiration date.

Knowing how the revenues are collected by the ISO or RTO, the time at which the option should be exercised can be established based on maximization of the expected revenues over the cost recovery period.

Consider a simple example using a commonly approved rate design employed in the US power industry. An annual rate (*AR*) is computed based on the highest one coincident peak (1CP) of the zone and the total capital investment. The 1CP formulation is used to illustrate how a simple cost recovery mechanism is able to incentivize transmission investment *if* transmission cost can be fully recovered. The 1CP formulation has also been allowed by FERC and therefore is used in this paper. Specifically, in planning the system, the expansions and reinforcements identified at peak load are the Transmission Owner's obligations to build to meet the reliability standards and criteria. The philosophy is that a system must be able to reliably serve its peak load. Otherwise, the reliability of the system might be compromised. NERC reliability standards and criteria are designed for planning the system at peak load. Since the peak load is the benchmark for transmission reinforcements, the peak load is used to determine the transmission rate.

Specifically, the *AR* (in \$/MW-year) is determined by dividing the annual revenue requirement (a percentage of the total transmission cost) by the highest coincident peak of a transmission zone. The daily revenue due to daily peak demand is denoted $R_1(t)$ and can be determined as

$$R_1(t) = DDV(t) \times \left(\frac{AR}{365} \right) \quad (1)$$

where $DDV(t)$ is a Daily coincident peak Demand Value. The daily peak demand is used, instead of hourly energy charges, in order to simplify the discussion.

Note that the proposed method can incorporate the financial instruments such as transmission rights that are awarded to TI as an added incentive once the project is in operation. Although the main cost recovery mechanism proposed in this research is still based on (1), transmission rights can be included in the formulation in order to evaluate the potential impact of such an added financial incentive. With revenues from the transmission rate and from the transmission rights, the total daily revenues collected by a TI are given by

$$R(t) = R_1(t) + R_2(t) \quad (2)$$

where $R(t)$ denotes the total daily revenues, $R_1(t)$ revenues due to a transmission rate, and $R_2(t)$ revenues due to transmission rights. Because of the random nature of the daily demand and nodal prices, the total daily revenues $R(t)$, $R_1(t)$ and $R_2(t)$ are all stochastic. As a result, the value of the return from the project is also stochastic. Note that (2) takes into account uncertainty from energy demand ($R_1(t)$) and market operation ($R_2(t)$), i.e., bidding strategy, fuel cost, and generally all market uncertainties are captured by nodal prices that dictate the revenue from the transmission rights.

The proposed formulation can be simplified when revenues come from only one source, either transmission rate or transmission rights. For example, if only a regulatory approved rate is allowed to recover the transmission investment cost, the second term of (2) ($R_2(t)$) will be zero. Alternatively, if financial instrument is the only recovery mechanism, the first term will be zero.

Options are financial instruments for profit seeking and risk management. Perpetual options are options without an expiration date. When a perpetual option is exercised, an investor is obligated to a financial agreement, which, in the context of this research, is to invest in a merchant transmission project.

An option to invest should be exercised when the present value of the expected revenue collected over the recovery period minus the investment cost is maximized. The corresponding optimal time to exercise the option is denoted by T_i. Due to the waiting time T_i, the total revenues need to be discounted over time. The expected value of revenues is calculated over an interval from the exercise time T_i to the end of the cost recovery period T_F, that is,

$$E\left\langle \left(\int_{T_i}^{T_F} R e^{-\rho t} dt \right) e^{-\rho T_i} \right\rangle \tag{3}$$

where $E\langle\cdot\rangle$ denotes the expected value, and ρ is a discount rate. In (3), revenues to be collected between T_i and T_f are discounted back to the initial time T_i with the discount factor ρ, which can represent inflation, etc. during that period. The integral, i.e., the total discounted revenues collected within T_i and T_f, is discounted from T_i to T_o with the same discount factor. Note that T_o is the present time.

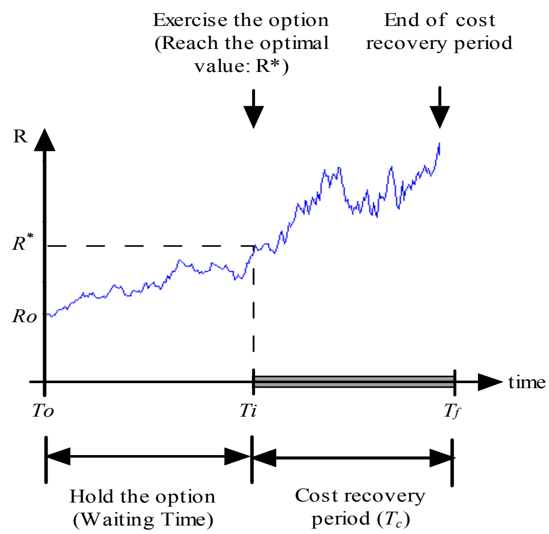

Figure 1. A realization of random revenues and the waiting time

An optimal exercise revenue (R^*) is reached at time T_i when $E\langle\cdot\rangle$ is maximized. It is assumed that an investor can begin to recover the investment as soon as the option is exercised. Specifically, the revenue during the construction period is collected under the Allowances for Funds Used During Construction (AFUDC). Fig. 1 illustrates the random nature of revenues over the waiting and cost recovery periods of the option. Although revenues are not collected over the holding period, they can be observed through the forecasted AR, peak demands and nodal prices.

It is seen that the end of the holding period, T_i, in Fig. 1 is the first time for the revenue to reach the optimal value R^*. Since R is random, T_i is not a deterministic value. This paper proposes a strategy to compute the optimal revenue value R^* and the waiting time. The waiting time is described by a cumulative distribution function (CDF). It is assumed that (2) is used for cost recovery over the time period between T_i and T_f.

2.2 Investment Decision Time: A Deterministic Approach

A common industry approach to recovering the investment is to develop an annual revenue requirement and its associated fixed rate based on the capital cost of the project and forecasted load. A Transmission Owner (TO) then uses this FERC approved rate to recover the investment. If the actual load is lower than the forecasted load, a TO can file a rate case in hope of getting a higher rate to make up for the difference. However, in today's regulatory environment, there is no guarantee that a higher rate will be approved.

Assume that the decision can wait. An approach that reflects the industry practice is given here. The method can be used to determine a corresponding waiting time and cost recovery based on the 1CP rate design.

1. Establishing an annual revenue requirement denoted as RR (\$ / year) based on the capital investment, rate of return, inflation, taxes, and depreciation, O&M expenses, etc.
2. Setting up 1CP rate formula as the cost recovery mechanisms given by yearly rate $AR = RR/H$ (\$ / kW / year) or daily rate $AR = RR/H/365$ (\$ / kW / day). H

represents the most recent single highest coincidence peak of the zone in kilowatts.

3. Forecasting the load throughout the life of the project.
4. Determining the waiting time that is computed based on the present value of the revenues over the cost recovery period discounted at a rate ρ. The present value PV of the stream of revenues over the cost recovery period is give by

$$PV = \sum_{n=1}^{Tc} \left(\frac{RR}{H} \right) \left(\frac{F(1+x)^{n-1}}{24} \right) \left(\frac{1}{1+\rho} \right)^{n-1} \tag{4}$$

where F is the forecasted total annual energy in kW-hour and x is the percentage of load growth. In (4), the present value is the summation of the discounted revenues over the cost recovery period T_c. For each year, the discounted revenue is the annual rate AR times the forecasted annual energy, which is the second term of the expression inside the summation, and the discount factor (the third term) that brings the value of the revenue of that year to the present time.

The PV over the project life will be compared to the capital investment. If the capital investment is not fully recovered, the project should be moved one year later, i.e., equation (4) is computed from $n = 2$ to $n = T_c + 1$. The investment decision year will be when the present value of the decision year is equal to the capital investment at the same year taking inflation into account. Since load is a random variable, the revenue may be over- or under-collected. As a result, there is no assurance that the cost will be fully recovered. The waiting time obtained from the methods described in sections II and III will be compared later.

2.3 Investment Decision Time: Perpetual Option Approach

An outline of the procedure for finding the optimal value R^* and the waiting time using the options approach is as follows:

1. Establish a mathematical model that best fits the behavior of R over time.
2. Establish the optimal revenue condition R^* where the option is exercised.
3. Based on the optimal condition R^*, the CDF of the waiting time is obtained by computer simulation of a large number of realizations of R.

2.3.1 Revenue Model

A stochastic model for the revenue R is needed, which, based on (2), is determined by *DDV*, *AR,* and transmission rights. A time series from the historical data can be used to identify a mathematical model that better fits the time series. Specifically, a stochastic process is required. Various stochastic processes (e.g., a Brownian motion, Mean Reverting Process) may be suitable to model the time series. However, this study identifies a special case of the generalized Wiener process, or Geometric Brownian Motion (GBM) [22]-[23]-[26], as the best suited for the following reasons:

1. GBM captures the non-negative characteristic of the revenues, i.e., equation (1) and (2) only have positive values over time. Other stochastic processes such as Brownian Motion (BM) and Mean Reverting Process (MRP) are not considered since they allow having negative and positive values over time.

2. GBM captures the fact that the daily revenue is expected to increase over time. This is a consequence of the increment of DDV. MRP tends to approach a stationary non-increasing value in the long run.
3. GBM allows a closed form for R^* and simplifies the analysis and computation.

The mathematical representation of a GBM is given by

$$\frac{dR(t)}{R(t)} = \mu dt + \sigma dz \tag{5}$$

where μ is the annualized expected return of revenues, σ is the annualized volatility of the revenues, and dz is a standard Wiener process given by $dz = \varepsilon\sqrt{dt}$ with $\varepsilon \sim N(0,1)$, which represents a normal distribution with 0 mean and 1 standard deviation. Note that (5) describes how revenue evolves over time, i.e., the continuous-time version of $R(t)$. However, $R(t)$ at a future time t is a random variable whose distribution is given by [27]

$$\ln R(t) \sim N\left(\ln R_o + \left(\mu - \frac{\sigma^2}{2}\right)t, \sigma\sqrt{t}\right) \tag{6}$$

where $\ln R(t)$ is the natural log of revenues, and R_o represents the initial value of the revenues as shown in Fig. 1. The present value when revenues are described by (5) is different from the PV described in (4). GBM provides a closed form to calculate the present value of expected future revenues from a time T_o to infinity, i.e., [24]

$$PV(T_0) = E\left\langle \int_{T_o}^{\infty} R(\tau)e^{-\rho\tau}d\tau \right\rangle = \frac{R_o}{\rho - \mu} \tag{7}$$

2.3.2 The Optimal Revenue Condition or Optimal Investment Value

An investment would be more attractive if one is able to wait and make investment decision after new and favorable information arrives. An investment is less risky if one can forgo the commitment when the information is unfavorable. Having the opportunity to wait for new information such as load tendency, market operation, regulatory approved rate designs, etc. adds monetary value to an option. Similar to holding a stock option, there is an opportunity cost or investment opportunity associated with the option. Hence, in applying the option theory, the total investment cost should include the capital cost of the project and this opportunity cost.

Let $F(R)$ represent the value of the option to investment. For this research, the $F(R)$ is a function of the revenues implying that future uncertainties are fully captured by R. Other sources of uncertainties such as contingencies, and market planning, are neglected for this study. The total investment cost is then $F(R)+K$ where K represents the capital investment. A TI can exercise the option when the expected revenues of the project are greater than the total investment cost. The investment opportunity is defined as the *maximum* expected value of revenues when the option is exercised at an unknown future time T subject to (5) [22]-[23].

$$F(R)=\max_{T} E\left\langle (R_T-K)e^{-\rho T}\right\rangle \tag{8}$$

where R_T is the present value of the revenues when the option is exercised at *T*. Equation (8) implies that an investment opportunity is the maximum expected present value of the *net payoffs.*

The decision problem proposed here is to find an optimal value R^* such that $F(R^*)+K=R^*/(\rho-\mu)$, i.e., when the total investment cots is equal to the expected future revenues of the project. Note that the proposed approach is an *extension* of the conventional Net Present Value analysis in which the NPV of the total investment cost must be at least equal to the *PV* of the revenue generated by the project.

To solve the optimization problem of (8), a differential equation that related (5) and (8) is established using option theory or dynamic programming and is given by [22]-[23]

$$\frac{1}{2}\sigma^2R^2\ddot{F}(R)+(\rho-\delta)R\dot{F}(R)-\rho F(R)=0 \tag{9}$$

Equation (9) is a second order differential equation where $\delta=\rho-\mu$, and satisfies the follow boundary conditions:

$$F(0)=0 \tag{10}$$

$$F(R^*)=\frac{R^*}{\rho-\mu}-K \tag{11}$$

$$\dot{F}(R^*) = \frac{1}{\rho - \mu} \qquad (12)$$

Equation (10) indicates that the investment opportunity is zero when there is no revenue. As mentioned in Section 2, R^* is the optimal value when the condition to exercise the option is met and the total investment cost $(F(R)+K)$ is equal to the present value of revenues (11). Equation (12) implies that the slope of $F(R)$ is equal to the slope of (7) at the optimal value. Taking into account all boundary conditions, the solution of (9) is given by

$$F(R) = AR^{\beta} \qquad (13)$$

where

$$\beta = \frac{1}{2} - \frac{(\rho-\delta)}{\sigma^2} + \left(\left(\frac{(\rho-\delta)}{\sigma^2} - \frac{1}{2} \right)^2 + \frac{2\rho}{\sigma^2} \right)^{1/2} > 1 \qquad (14)$$

$$R^* = (\rho - \mu)\left(\frac{\beta}{\beta - 1} \right) K \qquad (15)$$

$$A = \frac{1}{(\rho - \mu)\beta\left(R^*\right)^{\beta-1}} \qquad (16)$$

Note that $F(R)$ is a monotonic convex function. The maximum value is given when the slope of (12) matches the slope of the net present value (7), i.e., boundary condition (12). Note that the net expected present values (7) is less than $F(R)$ for values for $R \le R^*$.

R^* is the first time at which the revenue reaches the optimal value. Since R is a random process, it is possible for the revenue to fall back below the optimal value at a future time. However, the random process model here, Eq. (5), is Geometric Brownian Motion

(GBM) with a "drift" μ, which means that the expected value of the revenue will increase over time at the rate of μ. Hence, although the revenue may fall again for some realizations of the random process, the general trend is to move up again and therefore, the optimal condition is still met.

2.3.3 The Waiting Time

The waiting time T_i is defined as the time when the optimal value R^* is reached for the first time. Due to the stochastic nature of the revenues, the waiting time is a random variable whose cumulative distribution function is given by

$$CDF_{T_i}(t^*) = P\{T_i \le t^*\} \tag{17}$$

where $CDF_{T_i}(t^*)$ denotes the probability of reaching the optimal value at or before t^*. Note that the CDF of the waiting time depends on the initial value R_o as it is indicated in Fig. 1. Different initial values R_o lead to different CDFs. Higher values imply a shorter waiting time since R_o is closer to the target value R^*. In this study, the CDFs are obtained for a large number of realizations of (5) by simulations. The proposed simulation method consists of repeated simulations of (5) over the same time interval and records the value of t where the optimal value R^* is reached for the first time.

2.4 Numerical Results

A 5 bus system is used for the case study to illustrate the proposed methodology. Fig. 2 shows a potential merchant project according to TI or RTO economic analysis.

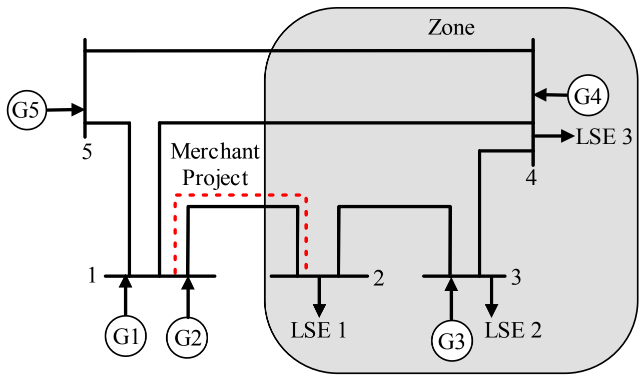

Figure 2. A merchant project in a 5 bus system

For illustration purpose, assume that the project shown in Fig. 2 is worth \$150M and the annual revenues requirement, *RR*, is about 16% of the project or \$24M. Note that economic factors such as inflation, depreciation and taxes can be incorporated into the annual rate calculation. Specifically, the annual rate here is determined based on the capital investment, rate of return, depreciation, O & M expenses, etc. When all these economic factors are considered, the annual revenue requirement is roughly 16% of the capital cost based on industry experience. The highest daily peak value of Zone 1 in Fig. 2 is assumed to be 4100 MW. The cost recovery period is assumed to be 40 years, and the yearly and daily annual transmission rate, respectively, based on 1CP formula rate are given by

$$AR = \frac{RR}{H} = \frac{24 \times 10^6}{4100} = 5{,}853.66 \left[\frac{\$}{\text{MW - year}} \right]$$
$$AR = \frac{5{,}853.66}{365} = 16.037 \left[\frac{\$}{\text{MW - day}} \right] \qquad (18)$$

Fig. 3 shows the hypothetical historical revenues from daily demand and transmission rights. The sum of $R_1(t)$ and $R_2(t)$ corresponds to the total revenues $R(t)$, which is used to compute GBM parameters. $R_1(t)$ is based on (1), i.e., historical daily peak demand multiplied by the daily rate in (18). $R_1(t)$ exhibits a seasonal behavior as can be seen in Fig. 3. On the other hand, revenues from transmission rights exhibit steadily increment that reflects their values due to differences in Locational Marginal Prices from system congestion. Since the result shows that the total revenues consist mainly of transmission rate revenues, it can be argued that transmission rate could provide adequate return of investment and the necessary incentive to build these projects. Other benefit from rate based recovery is that the risk coming from strategic planning of different participants is reduced, i.e., other's decision, which affects nodal prices and thus transmission revenues, are not taken into account. Additionally, the cost recovery of one project is not a function of the others' projects under the rate structure. Therefore, multiple projects can be evaluated by the Regional Transmission Organization separately.

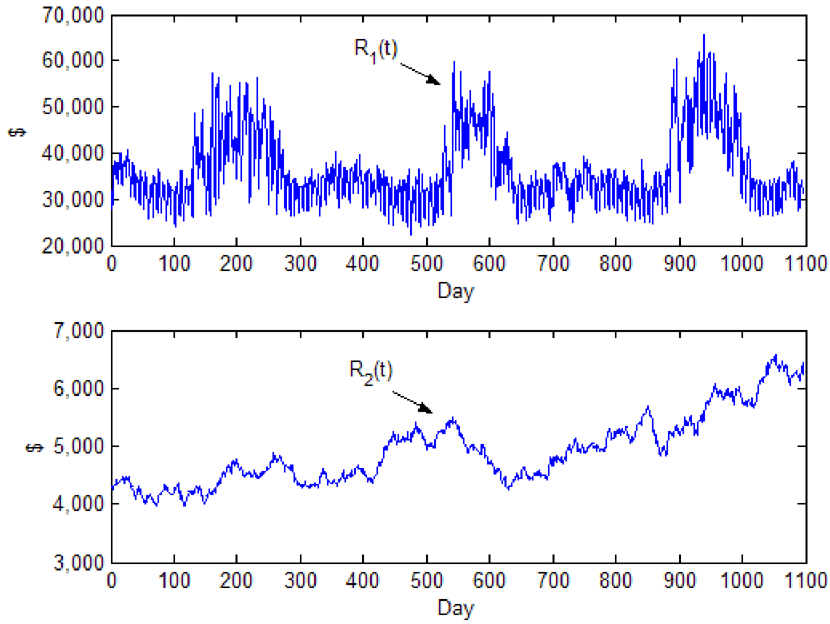

Figure 3. Historical Daily peak Demand Value (DDV) and transmission rights

The data shown in Fig. 3 are used to forecast future daily revenues. The parameters μ and σ of (5) that fits the summer peak values are found using maximum likelihood estimation [27]. Only summer peak values are taken into account for parameter estimation because they normally exhibit high volatility and more uncertainty. The annualized expected return of revenues μ is *0.1095* and the annualized volatility σ is *0.1043*. Having the GBM parameters and assuming a discount rate ρ of 13%, the optimal value when the option must be exercised based on (13)-(14) is $R^* =$ \$20.460M

The revenue R_0 at time T_o in Fig. 1 is based on the 1CP rate, daily peak demand value and revenue due to transmission rights. The peak demand value at T_o is assumed to be 4100MW (the highest daily peak demand value) so that the revenue $R_1(t)$ at T_o is given by $R_1(T_o)=16.037\times4100=\$65,751$. Similarly, revenues form the transmission right at T_o are assumed to be 10% of the revenues caused by the peak demand, i.e., $R_2(T_o)=\$6,575$. Together, the total revenues at T_o is $R(T_o)= R_0=\$72,326$.

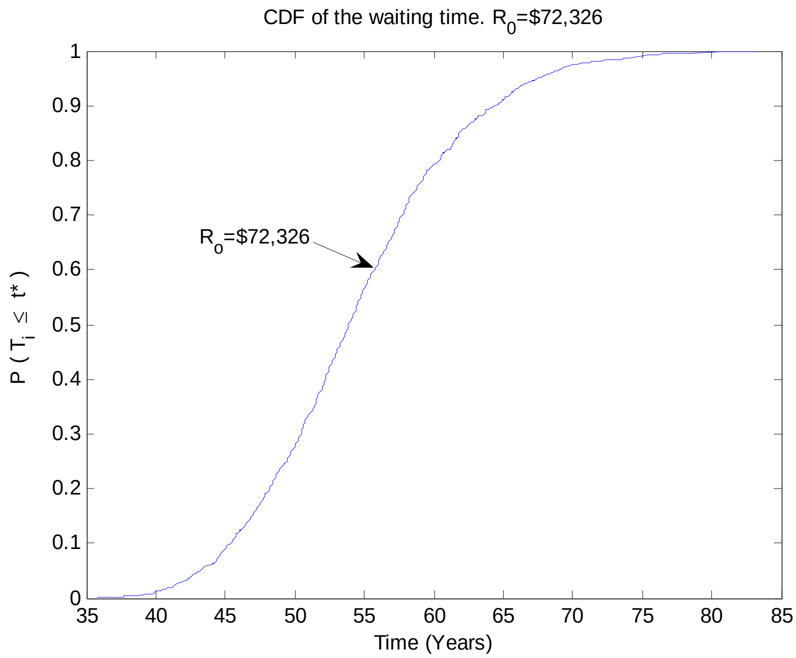

Figure 4. CDF of the waiting time. R_0=$72,326

The CDF of the waiting time is shown in Fig. 4. The horizontal axis represents time in years and the vertical axis represents the probability. The CDF is computed based on 5,000 realizations of (5) over a time horizon of 100 years. The time t^* when a realization reaches the optimal investment value of $R^* = \$20.460M$ for the first time is recorded for each realization. Based on the recorded times, the CDF of the waiting time (16) is obtained, which gives the probability for the (random) revenue R to reach R^* at or before time t. As shown in Fig. 4, it takes almost 85 years for the probability to approach 1. Note that a long waiting time does not encourage transmission investment. Therefore, an incentive to encourage transmission investment is needed, and thus reduces the waiting time.

Assume that the merchant transmission project has an initial incentive. The incentive is assumed to be a percentage of the capital investment that comes from allowance provided by the FERC. The rest of the investment cost is recovered by the proposed cost recovery mechanisms, i.e., using daily demand and transmission rights. Different initial values of R_0 are considered in order to evaluate sensitivity of the waiting time with respect to initial incentive R_0. Three initial incentive values are used, i.e., 8%, 10%, and 12% of the capital investment ($150M). Note that the optimal value R^* does not depend on the initial value R_0.

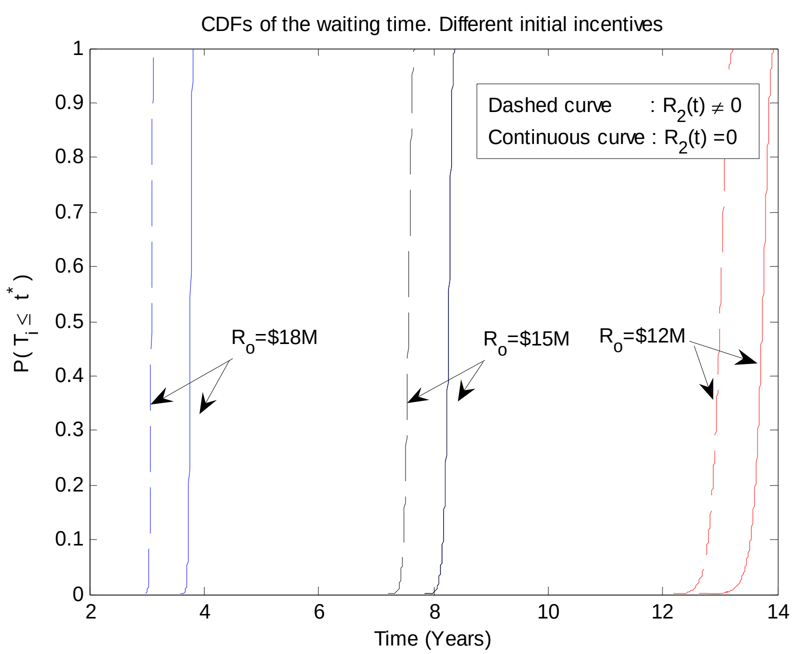

Figure 5. CDFs of the waiting time. Three different initial incentives

The CDF of the waiting time is shown in Fig. 5. Each curve is the CDF for a different initial value of R_o. The dashed lines represent the CDF when total revenues include transmission revenues. On the other hand, continuous lines are the CDFs when revenues do not include transmission rights, i.e., $R_2(t) = 0$. When transmission rights are considered, the optimal value R^* is likely to be reached at Year 3, Year 7, Year 13, for an initial incentive of $18M, $15M, and $12M, respectively. The left curve corresponds to the shortest waiting time which has the highest incentive ($18M). On the other hand, a lower incentive ($12M) leads to a longer waiting time as shown in the right curve. Note that the slope of the CDF represents the probability density of the waiting time at that point. Therefore, Year 3, Year 7 and Year 13 have high probability densities. The CDFs rise sharply at Year 3, Year 7 and Year 13. Note that the effect of having transmission rights is to decrease the waiting time.

Fig. 6 and Fig. 7 show the CDFs of the present value of revenues collected over the cost recovery period once the option is exercised, i.e., equation (2) for $T_{i=3}$, $T_{i=7}$ and $T_{i=13}$. The horizontal axis represents revenues in millions and the vertical axis represents probability. Dashed lines represent the CDF when transmission rights are included as a part of the cost recovery mechanism. On the other hand, continuous lines represent cases without transmission rights. A total of 5,000 realizations of (5) are computed for a time horizon of 40 years, i.e., the cost recovery period. All realizations have the same starting value of R^*. The present value of the revenue collected over T_c is recorded for each realization, i.e., each realization is a collection of daily revenues that are all discounted at $\rho = 13\%$.

A straight vertical line on the left side indicates the value of the capital investment and a return of 12%, i.e., $168M. Note that this is a deterministic value and hence it is a straight line. Although the option is exercised at the optimal point R^*, there is still a risk of not recovering the cost due to an unexpected decrement of the revenues as a consequence of a decrement of demand or revenues from transmission rights. The reason is that the method only provides the best estimate that the investment can be fully recovered but there is no guarantee that it will be the case due to market and demand uncertainties.

The risk of not recovering the capital investment and a 12% rate of return is given by the intersection of the vertical line with each CDF. Indeed, the probability that the cost of $168M will not be recovered for the case of R_o=12M (Fig. 6) is 0.25 when transmission rights are included and 0.64 without transmission rights. That is, the probability to recover the cost is 0.75 and 0.36 respectively.

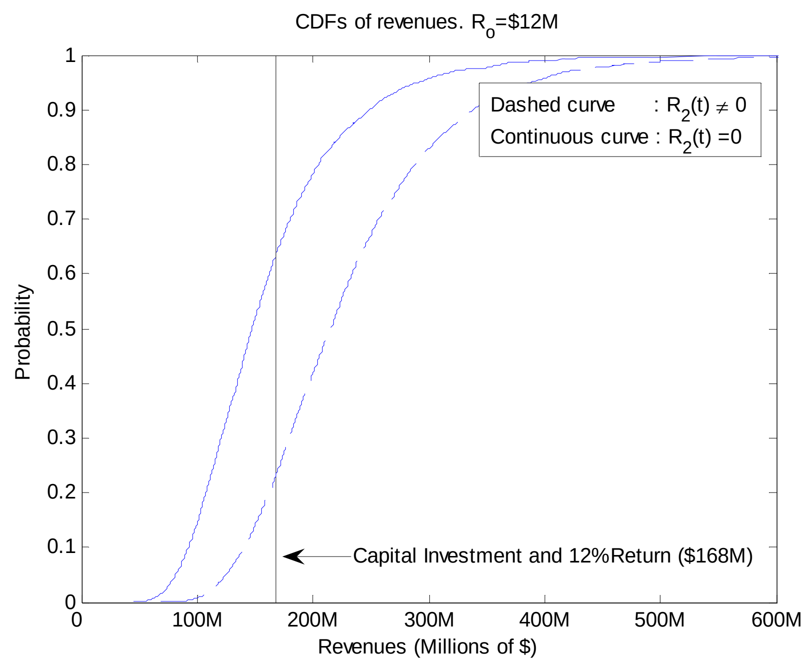

Figure 6. CDFs of revenues. Ro=$12M

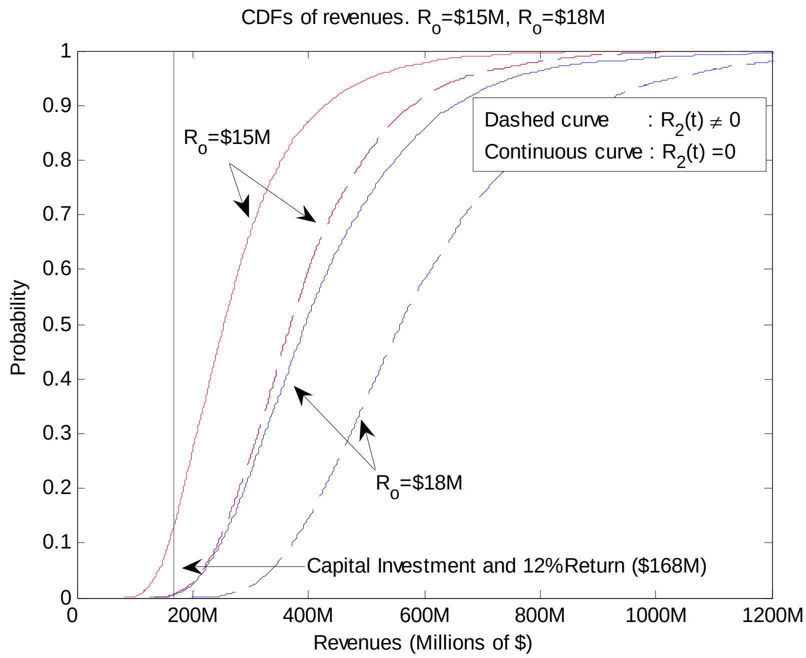

Figure 7. CDFs of revenues. Ro=$15M and Ro=$18M

Fig. 7 shows the CDFs corresponding to R_o = \$18M and R_o = \$15M. The curve of R_o = \$18M is able to recover the investment cost; the probability to recover the cost is 0.99. It implies that revenues based mainly on a fixed annual rate *AR* and peak daily demand values are sufficient as a cost recover mechanism. This greatly reduces the risk of a rate case revision. Note that allowing for the added revenue from the transmission rights decreases the waiting time and the risk of not recovering the capital investment for projects. However, if a high initial incentive is allowed, the rate based cost recovery method would be sufficient to encourage merchant projects without the added return from transmission rights as seen in Fig. 5 and Fig. 7.

Finally, in order to compare the option approach with the industry practice, the same merchant project is analyzed. Capital investment (\$150M), annual revenue requirement *(RR)*, the annual transmission rate *(AR)*, and the discount rate are the same. Load growth, *x,* inflation rate, and the forecasted total annual energy, *F* are 3%, 4%, and 1,000 MW-hr, respectively. Based on the industry practice described in section III, it is established that the merchant project should be built 8 year from the current date, i.e., the present value of forecasted revenues given by (4) at Year 8 is equal to the capital investment with 12% of return.

For comparison, assume that the initial incentive of 10% ($15M) is provided, no transmission rights are considered, and the option approach is used. The optimal value is likely to be reached at Year 8 according to Fig. 5. The CDF of revenues given in Fig. 7 is reproduced in Fig. 8. The deterministic investment time (8 years) is closed to the most likely value of the waiting time in Fig. 5. Note that the option approach allows an investor to take into account the random nature of revenues in the decision making process. In contrast, the deterministic approach does not model the stochastic revenues and the risk level is not quantified. Using the option approach, it is obtained that the probability to recover the cost is 0.86, as shown in Fig. 7.

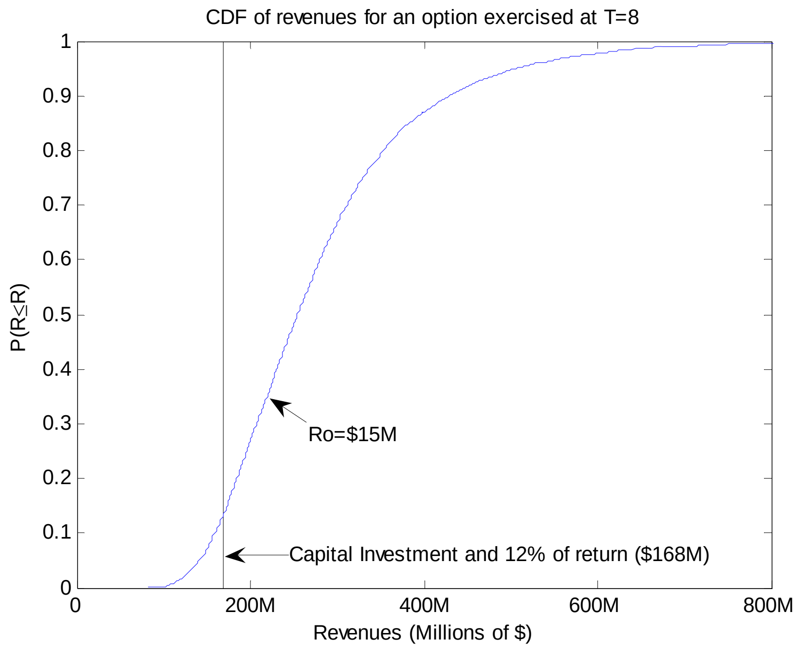

Figure 8. Revenue comparison between an option exercised at Year 8 and forecasted revenue based on industry practice

CHAPTER 3. RISK CALCULATION OF MERCHANT TRANSMISSION PROJECT USING KOLMOGOROV EQUATIONS

3.1 Problem Formulation

For a merchant transmission project, a *TI* can estimate the most opportunistic time to make the investment since merchant transmission projects do not have a firm commitment or completion date. In contrast, a reliability project has a definite commissioning date since it is needed to mitigate the reliability criteria violation by the transmission planner for a specific planning year.

The market rule for recovering merchant transmission investment varies from one market to another depending on whether the merchant project is rated based or market based. For example, merchant projects at PJM are likely to be rate based and the investment of these economic projects would be recovered by the FERC approved fixed transmission rate or a formula rate. In this chapter, a 1CP fixed annual network integration transmission service rate, denoted by *T,* in dollars / mega-watt-year [$/MW-year] is assumed as a cost recovery mechanism. Note that the assumed cost recovery mechanism is the same as chapter 2. Other cost recovery mechanisms such as incremental financial transmission rights or a two party transaction fee can also be used in the proposed approach. The 1CP network transmission service rate is calculated by the ratio of the annual revenue requirement of the investment to the zone's coincidental peak load. Having the transmission rate, a daily charge (*R)* is collected by the ISO based on a daily demand value *(D)* coincident with the annual peak of the zone, i.e.,

$$R = D * T / 365 \tag{19}$$

A monthly payment is made to the *TI* that is the sum of the daily values over all days of the month. Note that daily revenues *R* are stochastic due to the random nature of the *D (i.e. the daily demands).* Consequently, *the value of the project* defined as the *present value of future cash flow* is also stochastic. Equation (1) is similar to the daily charges collected by PJM using a network transmission service rate [39].

Perpetual option theory provides an investment criterion for projects whose revenues are stochastic. Since these projects do not have a specific time to start the construction, perpetual refers to the fact that the option to invest does not have an expiration time. Since the cost recovery mechanism defined by (19) is stochastic and the *TI* has no obligation to invest in the project, the theory provides an investment criterion that maximizes the expected present value of the revenues over the cost recovery period. As in the net present value technique, the options theory establishes an optimal value of revenues R^* at which the investor should exercise the option to invest. However, the capital investment might not be fully recovered due to uncertainties in the demand and hence, the revenues. As a result, the theory only provides the optimal expected return with no guarantee to fully recover the capital investment.

Once the option is exercised, the cumulative distribution function of the present value of daily revenues over the cost recovery period is used to calculate the probability of not recovering the cost of investment. The distribution is obtained using a large number of Monte Carlo simulations. Fig. 9 shows a hypothetical cumulative distribution function of the present value *PV* of the daily revenues *R*, i.e., *PV(R)*. The vertical straight line is the capital investment *K* of the merchant project. *K* is a deterministic value represented as a straight line. The intersection of the CDF and the straight line is the probability that *PV(R)* is less than or equal to *K*., i.e., $P(\ PV(R) \leq\ K\ )$. Note that $P(\ PV(R) \leq\ K\ )$ can also be computed directly from the Probability Density Function (PDF) if a closed form is provided.

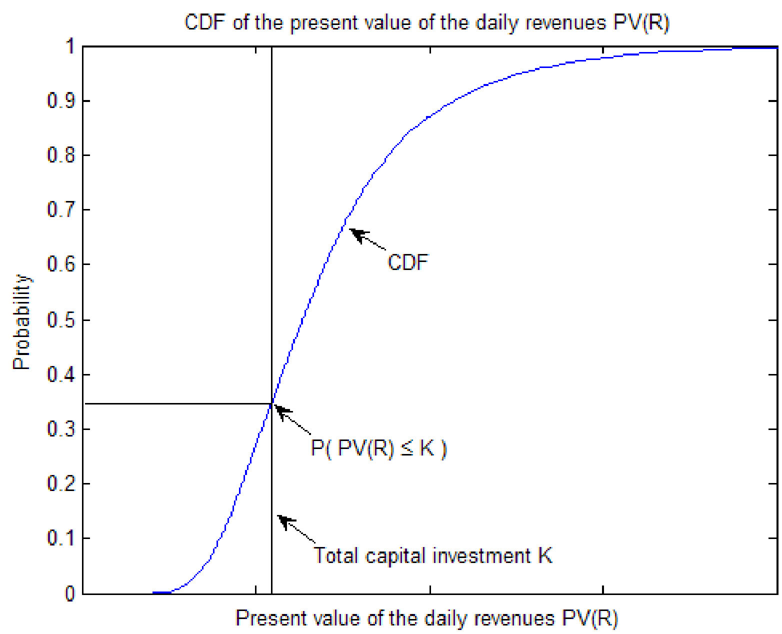

Figure 9. Cumulative Distribution Function (CDF) of the present value of the daily revenues *PV(R)*

It was mentioned that the option to invest can be exercised before the optimal value *R** is reached, i.e., an early exercise might be desirable if enough incentives are provided by the market regulators. Examples of such incentives are allowances approved by FERC, incentive adder to the rate of return on the investment, incremental financial transmission rights, etc. The probability of not recovering the capital investment before the optimal value is reached can be calculated using the PDF or CDF of the present value of the total revenues *given that* the option is exercised before $R*$. Having the capital investment K and the *conditional* PDF or CDF, the probability can be determined and used for making an investment decision. The next section explains how a condition PDF is obtained for a merchant project whose revenues are stochastic.

3.2 Early Exercise: A Quantitative Analysis

In this paper, daily revenues R described by (19) is modeled as Geometric Brownian Motion (GBM), i.e., the randomness of the daily revenue is captured by a Brownian motion. Chapter 2 provides a qualitative argument for the use of a GMB model when R is given by. The GBM model is given by (20)

$$\frac{dR}{R} = \mu dt + \sigma dz \tag{20}$$

where μ is the annualized drift of the revenues, σ is the annualized variance, and dz is a Wiener process: $dz = \varepsilon\sqrt{dt}$ with $\varepsilon \sim N(0,1)$ where ε symbolizes a normal distribution with 0 mean and 1 standard deviation. With a GBM model, it is possible to obtain a closed form solution of the optimal investment criterion $R*$ that is given by (21). Derivation of the optimal criterion can be found in [23].

$$R^{*} = (\rho - \mu)\left(\frac{\beta}{\beta - 1}\right)K \tag{21}$$

where ρ is the annual discount rate of future revenues. The parameter β is given by

$$\beta = \frac{1}{2} - \frac{\mu}{\sigma^2} + \left(\left(\frac{\mu}{\sigma^2} - \frac{1}{2}\right)^2 + \frac{2\rho}{\sigma^2}\right)^{1/2} \tag{22}$$

An illustration of the optimal investment criterion *R** is shown in Fig. 10. A comparison with traditional Net Present Value (NPV) criterion is shown in order to illustrate the significance of *R**. The straight line in Fig. 10 corresponds to the net present value. It is used only for illustrative purpose. The net present value is given by

$$NPV(R) = R/\rho_d - K \tag{23}$$

where ρ_d is the daily discount rate, and *M* is the investment criterion given by NPV. The investment criterion is the solution of (23), i.e., *NPV(R)=0*. According to the NPV rule, the *TI should* invest if the NPV is greater or equal to *M*.

On the other hand, the value of the option to invest in a project when the daily revenues follows (20) is denoted as *F(R)*, and corresponds to the convex curve in Fig. 10. The optimal invest criterion *R** when revenues are given by (20) and corresponds to the tangent point between *F(R)* and *NPV(R)*. Since β is greater than 1, and assuming that $\mu \geq \rho$, the optimal investment value R^* is greater than M according to (23). An interpretation of the results is that uncertainties from revenues would prevent a transmission investor to invest in the project. As a consequence, a higher return on the capital investment is required by investors or the investment decision is delayed until some uncertainty is resolved.

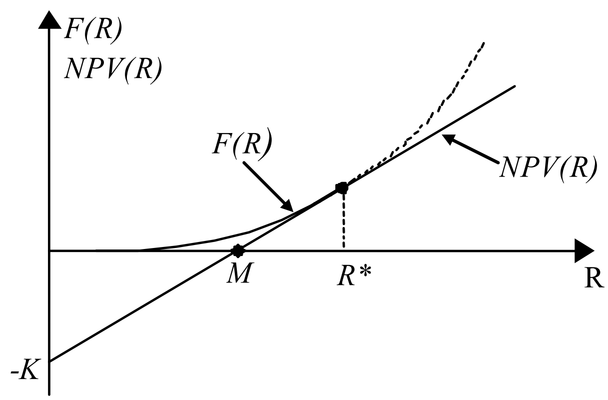

Figure 10. A comparison between the optimal investment criterion (*R) provided by perpetual option theory and the investment criterion (*M*) provided by the net present value rule**

The probability of not recovering the capital investment when the option is exercised for values between $M \leq R \leq R^*$ can be calculated using Kolmogorov forward equation. These are the transition probabilities which could be used to judge and make decision based on the likelihood of recovering the investment. Note that the option to invest is never exercised for values lower than M because it implies negative NPV implying that the capital investment may not be fully recovered.

To calculate the transition probabilities, the value of the project *(V)* is defined *as the present value of the future revenues*, i.e., $V = PV(R)$. By Ito's Lemma [22], it can be shown that V follows a GBM if R is given by (20), i.e., V is described as $dV/V = \mu_v dt + \sigma_v dz$ where μ_v is the annualized drift of the value of the project, and σ_v is the annualized variance of the value of the project. In other words, μ_v is the expected annual increment of the present value of the revenues and σ_v the volatility. Since V and R follow the same stochastic process, the comparison of Fig. 10 can be done in terms of V as well.

The transition probability, denoted as $\phi\left(V, t_1 \mid V_{t_o}, t_o\right)$, is a probability density function of the values of the project at t_1 given that the current value is V_{to}. A graphical interpretation of the transition probability is shown in Fig. 11. The x axis represents time, y the value of the project, and z probability. Fig. 11 shows a sample realization of V over time, i.e., $V(t)$. V^* denotes the optimal investment value in terms of the project value. The optimal value of the project can be derived from (21) and is given by $V^* = \left(\beta_v/\left(\beta_v - 1\right)\right)K$ where β_v is given by (22) replacing μ and σ by μ_v and σ_v respectively.

The shadow area indicates the probability that the future value of the project is equal to or less than the capital investment K given that the current value of the project is V_{to}.. Mathematically,

$$P(V \leq K, t_1 \mid V_{t_o}, t_o) = \int_{-\infty}^{K} \phi\left(y, t_1 \mid V_{t_o}, t_o\right) dy \tag{24}$$

A closed form for the transition probability can be obtained using Kolmogorov forward equations [22] - [40]. The closed form is possible based on the assumption that the daily revenues and the project value follow a GBM. The transition probability is given by [40]

$$\phi\left(V,t_1 \mid V_{t_o},t_o\right)= \frac{1}{\sigma_v V\sqrt{2\pi(t_1-t_o)}}\exp\left(-\frac{1}{2\left(t_1-t_0\right)\sigma_v^2}\left[\log\left(V/V_{t_o}\right)-\left(\mu_v-\sigma_v^2/2\right)\left(t_1-t_0\right)^2\right]\right) \tag{25}$$

According to (25), the transition probability depends on the parameters of the GBM process μ_v, σ_v and the difference between the current time t_0 and the future t_1. The next section will compute various transitions probability for future time values.

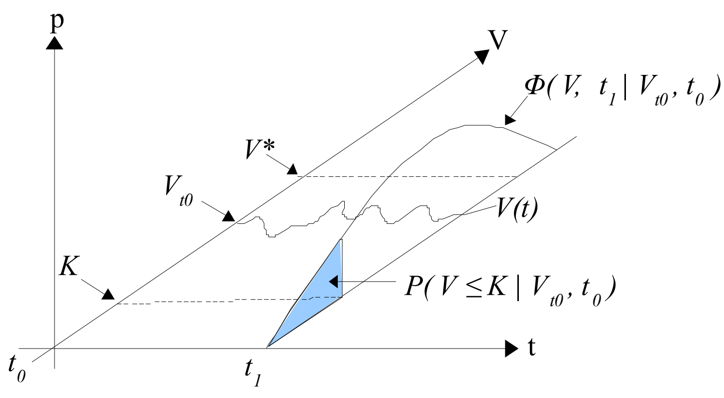

Figure 11. Transition probability

3.3 Numerical Results

3.3.1 Project Description and the Value of the Option

Consider that the revenues of a rate base transmission project follow a GBM process. The parameters of *R* are estimated based on historical daily peak demand values, transmission rate and the cost recovery proposed by (1). Having the GBM parameter, μ_v and σ_v are estimated using Ito's Lemma. Assume for simplicity that the annual drift and the annual standard deviation of the value of the merchant project are $\mu_v = 0.05$ and $\sigma_v = 0.1$ respectively. The drift represents the expected increment of future cash flows when there is no uncertainty. The value of the merchant project is therefore expected to increase 5% every year. The standard deviation is a measure of the uncertainty in future cash flows, i.e., volatility. The capital investment of the merchant project is *K=$150* million, and the discount rate of future cash flows is $\rho=10\%$.

Having the GBM parameters and the discount rate, the optimal investment value is $V^* = 2.1844 \times K = \$327.66$ millions according to (21) and (22). Fig. 12 shows the value of the option *F(V)* and the net present value *NPV(V)* as a function of the value of the project *V*. The tangent point gives the optimal investment value. Note that $V^* \geq M$. Fig. 12 shows that the net present value rule could *underestimates* the investment because the criterion provided by net present value rule ignores uncertainty from future revenues. In contrast, the optimal criterion V^* is higher than *M* as a consequence of the uncertainty in future cash flows. Note that the effect of a higher investment criterion entails a longer waiting time, i.e., the *TI* has to postpone the investment even though the present value exceeds the capital investment. This extra time translates in higher return and is beneficial to the *TI*. It gives an additional time to evaluate the return from the electricity market and thus make a better investment decision.

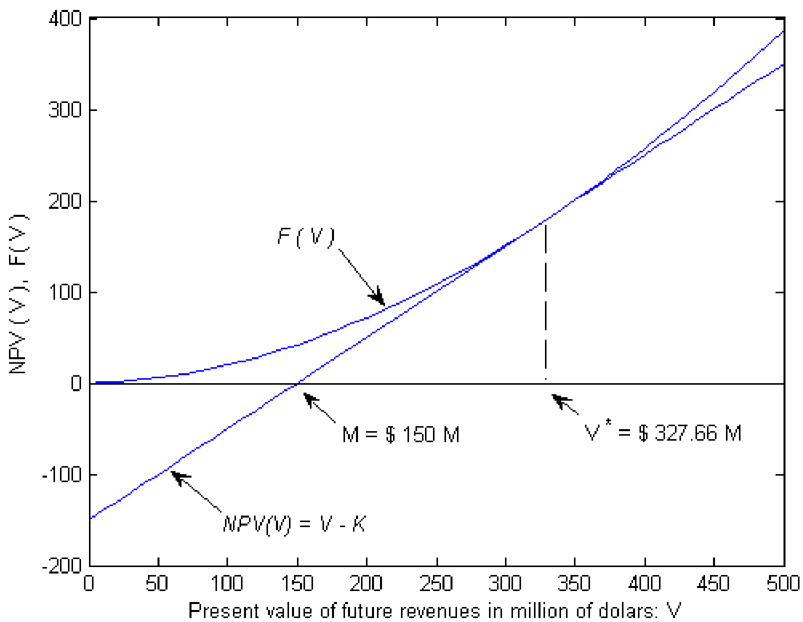

Figure 12. A comparison of the value of the option *F(V)* and the net present value *NPV(V)*

The difference between *M* and *V** is given by the parameters of the stochastic process and the discount rate. For instance, a project with higher volatility implies higher standard deviation. If the standard deviation is increased to 15%, the optimal value is $V^* = 2.3844 \times K = \$358.076$ million. This value is higher than the optimal investment value with a lower standard deviation. High optimal investment values imply that revenues are more volatile. As a result, the *TI* will demand a higher rate of return on the investment. Fig. 13 shows the relation between the standard deviation and the investment criterion *V**. The figure confirms that additional uncertainty raises the optimal investment value. In order to promote transmission investment, additional incentives may be needed to compensate for the uncertainty.

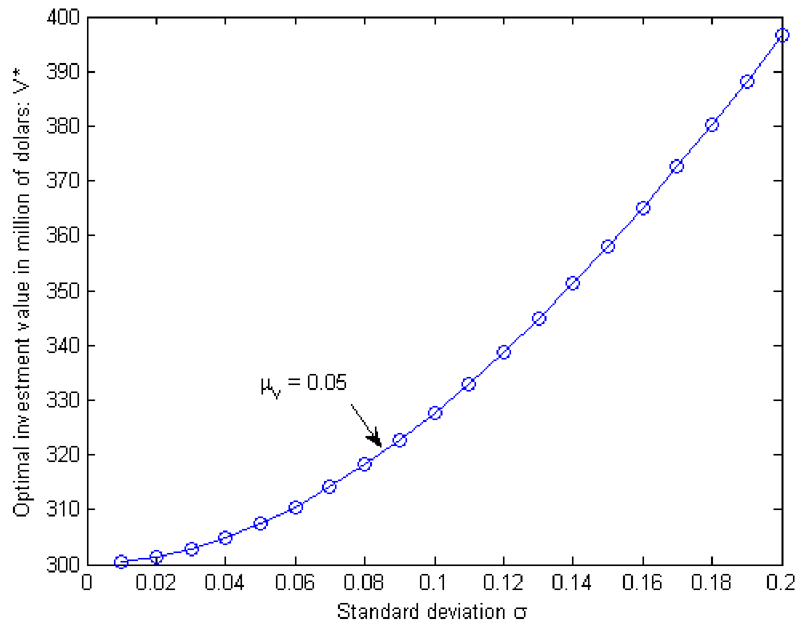

Figure 13. Optimal investment value *V as a function of the standard deviation**

3.3.2 Risk Assessment: Conditional Probability Approach

Figure 14 shows the probability of not able to recover the capital investment K at future time even when net present value is positive, i.e., $NPV = V_{to} - K = \$160M - \$150M = \$10\ M$. The horizontal axis in Fig. 14 represents time in Years and the vertical axis probability. Equation (24) and (25) are evaluated for different values of t_1. Take for instance $t_1=2$. Equation (25) gives the transition probability of the values of the project at $t_1=2$. The transition probability at $t_1=2$ is a conditional PDF of the value of the project given that the current value is $V_{to}=\$\ 160M$. The probability that the value of the project at $t_1=2$ is less than or equal to the capital investment $K = \$150M$ is 0.137 according to Fig. 14. Hence, it is likely that the project will recover the capital investment in two years. Note that this probability is computed for values at t_1. Note that Fig. 14 corresponds to associated risk of an early exercise because the current value V_{to} is lower than V^*.

The conditional probability generally decreases over time due to the assumption of the mathematical model assumed. According to (20), daily revenues (or the value of the project) increase over time because of the expected increment of daily peak demand values. As a result, the risk of not recovering the investment is expected to decrease as the model suggests. For instance, the conditional probability is roughly 0.08 at $t_1=6$. That means the risk of not recovering the capital at $t_1=6$ is roughly 0.08 when the option to invest is exercised at $V_{to}= \$160M$.

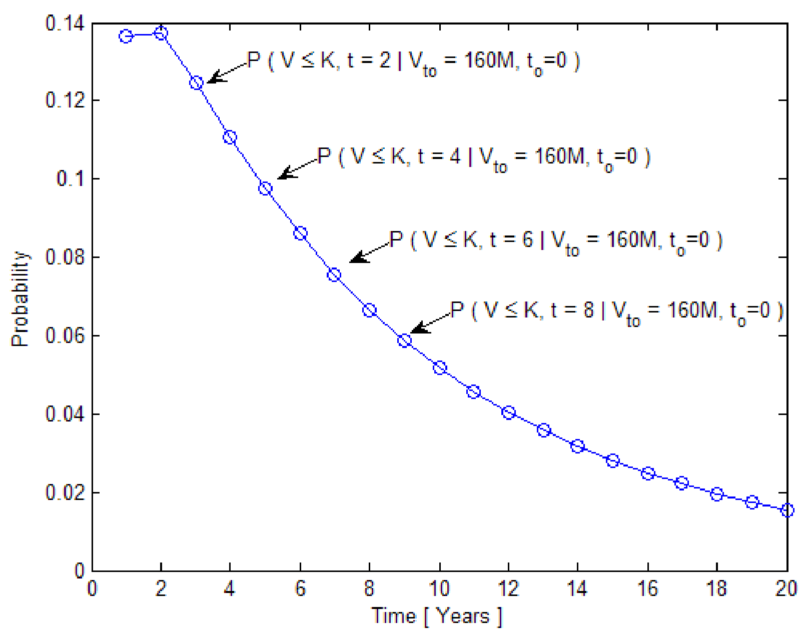

Figure 14. Risk assessment of an early exercise before the optimal investment value $V^*= \$327.66$

Figure 15 shows the value of the conditional probability for different values of V_{to} evaluated at different times. The x and y axes represent time and the value of the project respectively. The axis z is the conditional probability. The current value of the project is the value at which the option can be exercised. Note that all the values are lower than the optimal investment value $V^* = \$327.66M$.

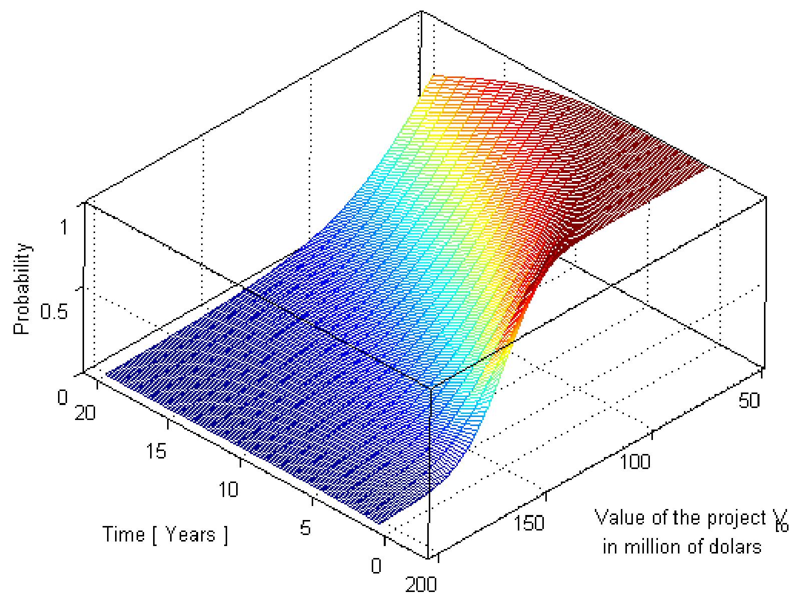

Figure 15. Risk assessment of an early exercise for different values of V_{to}

Three different scenarios are analyzed. Take for instance a value of $V_{to}= \$50M$. According to Fig. 12, the net present value is negative and the investor should not invest. The conditional probability of a project whose current value is $V_{to}= \$50M$ shows that the risk of not recovering the capital investment slightly decreases over time. It remains above 0.6 at year 20. In other words, it is unlikely that the value of the project *at year twenty* will be greater or equal to the capital investment. For this scenario, the net present value criterion and an early exercise clearly suggest that the investment is not profitable. Consider an optimistic scenario where the value of the project is V_{to}= *$200M*. This value exceeds the capital investment. The net present value is positive according to Fig. 11 and therefore the investor should invest. The same conclusion can be drawn from the conditional probability. Fig. 15 verifies that for a value of V_{to}= *$200M* the conditional probability is lower than 0.01 at $t_1 = 1$. Since the conditional probability is expected to decrease according to Fig. 14, it is highly likely that the capital investment will be recovered. For this case, the net present value rule and the conditional probability lead to the same decision. Note that the net present value and the conditional probability lead to the same conclusion for extreme values such as scenario 1 and 2.

The final scenario analyzes a project whose current values is V_{to}= *$130M*. Note that this value is less than the capital investment K = *$150M*. According to the net present value rule and Fig. 12, the investment is not profitable since the net value is less than zero. The conditional probability when the option to invest is exercised at a value of V_{to}= *$130M* is shown in Fig. 16. The black line represents the conditional probability. The surface is the conditional probability for different values of V_{to}. The surface is the same as Fig. 15. The highest value of the conditional probability is 0.83 and the lowest value 0.045. The lowest value indicates that the capital investment is likely to be recovered even though the option is exercised at a value much lower than the optimal value. Note the discrepancy between the net present value criterion and the perpetual option criterion. The first technique suggests not investing. On the other hand, a risk analysis based on option theory suggests, for the same value of the project, investing because the capital investment is likely to be recovered in the long term. Finally, observe that the optimal investment value provided by the option theory

V^*=$327.66M is higher than $130M. If the *TI* waits until the optimal value is reached, the capital investment will be recovered with a high degree of certainty according to this analysis. However, the waiting time can be extremely high which might not incentivize transmission investment. This alternative analysis suggests that an early exercise might be profitable, and therefore encourages transmission investment.

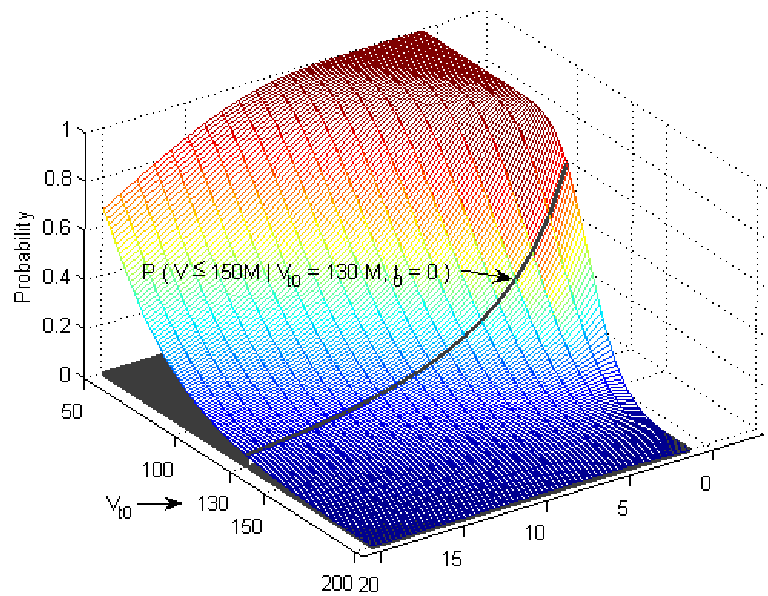

Figure 16. Risk assessment of an option exercised at V_{to} = *130 M*

CHAPTER 4. TRANSMISSION RATE DESIGN FOR A MERCHANT TRANSMISSION PROJECT

4.1 Problem Formulation

Consider a Merchant Transmission Project (MTP) that connects two separate zones as shown in Fig. 17.

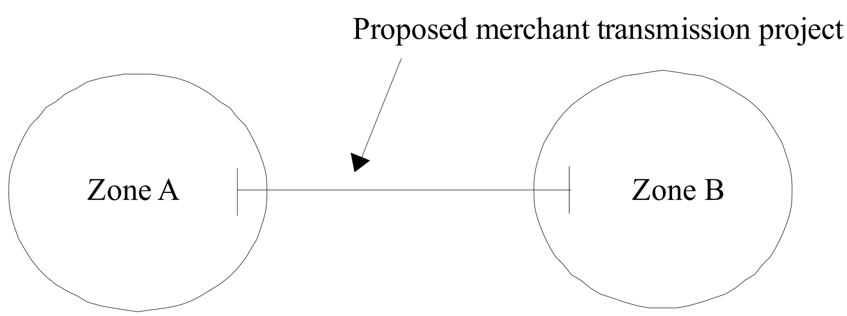

Figure 17. A two-zone system

Assume that the annual average zonal energy price and capacity price of zone A is given by $\overline{P}_A$ and $\overline{C}_A$, respectively. Similarly, $\overline{P}_B$ and $\overline{C}_B$ corresponds to the annual average zonal energy price and capacity price of zone B, respectively. Suppose that energy price and capacity payments in zone B are higher than those in zone A, i.e., $\overline{P}_B \geq \overline{P}_A$ and $\overline{C}_B \geq \overline{C}_A$. Additionally, zone A has a surplus of electric energy that can be exported to zone B. Note that the merchant transmission line is a market-driven economic solution if the economic benefits (energy price and capacity price reduction in zone B) derived from the project are higher than the total investment cost.

Suppose that zone A can guarantee economic surplus to zone B over a specific period of time. A firm contract transmission service can be established between a zone B customer and the transmission provider (or investor) in order to import electric energy with the guaranteed transmission access. The firm contract provides a fix transmission line capability that is used to import energy from zone A. The firm contract can be offered to those customers in zone B who are interested in importing cheaper energy, through an open bidding process. The contract guarantees a deterministic cash flow to the provider, and therefore it reduces the risk of not recovering the capital investment in the new line.

Suppose that, in addition to the guaranteed economic surplus, there is an excess of surplus energy from zone A that can not be fully guarantied. Outages of generating units, contingencies in zone A, etc., can cause the cheaper energy to become unavailable. The capacity of a merchant line project can be modeled as a combination of a guaranteed economic surplus and a random component of surplus, as shown in Fig. 18.

Based on the previous considerations, this research proposes that the transmission provider recovers the capital investment via three mechanisms – (1) revenues from firm contracts, (2) revenues from incremental FTRs, and (3) revenues from a transmission rate based on a random component of cheaper energy. It is observed that the future cash flow has two random components, i.e., revenues from incremental FTRs and the transmission rate.

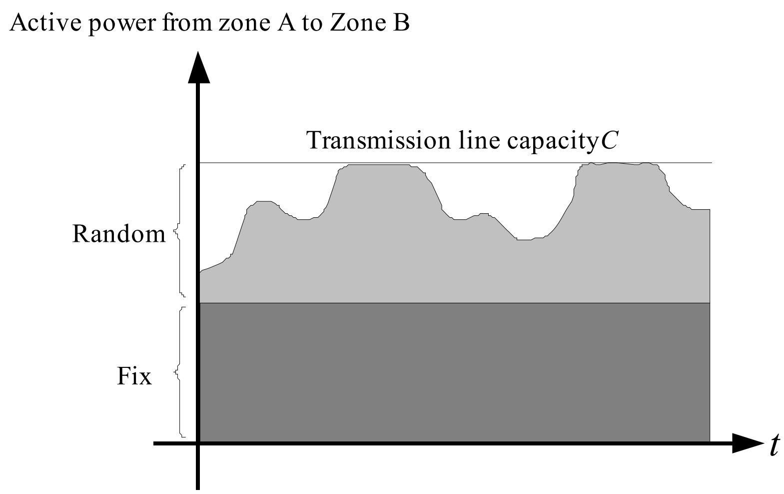

Figure 18. Merchant transmission line utilization

In this research, a Transmission Rate (*TR*) is proposed as an additional recovery mechanism to increase the revenues and provide the needed incentives for enhancement of the transmission grid. Transmission rates are widely used by industry and regulatory agencies as a cost recovery mechanism. These rates are established ahead of time based on agreed formulas. Transmission rates are established based on the annual revenue requirement by the transmission developer, subject to the approval by FERC. Inflation, operation and maintenance, depreciation, and other economical factors are included in the calculation of the annual revenue requirement. However, the current practice of the transmission rate calculation does not include *the economic benefits* that the project brings to transmission customers and the power grid. In other words, TRs are normally cost-based rather than market-based. This is an important extension proposed by this research that is more appropriate for a competitive industry. The proposed approach establishes a transmission rate based on the following considerations:

1. Transmission customers are willing to pay for the MTP since energy price and capacity payments are expected to decrease once the project is in operation.
2. Transmission investors intend to maximize the economical benefits from the investment. Furthermore, transmission investors are able to recover the capital investment within a certain confidence level.

An important feature of the proposed approach is that the design of the transmission rate does not rely only on traditional industry practice, i.e., cost-based and revenue requirement. The market incentive (total market savings) necessary for a competitive environment is included as part of the mechanism design. The new design is expected to incentivize transmission customers to pay for a MTP based on the fact that economic benefits can be realized. Transmission investors are also incentivized since the investment can be recovered and the risks can be managed.

4.2 Mathematical Formulation

It was mentioned that the cost recovery mechanism is based on revenues from firm contracts, transmission rate and incremental FTRs. Hence, the daily revenues $R_{j,}$ for day j are can be obtained as follows:

$$R_j = FTC_j + R_{TR_j} + R_{FTR_j} \tag{26}$$

where FTC_j are daily revenues from firm transmission contracts. The term, R_{TRj}, corresponds to the daily revenues from transmission rates, and the last term, R_{FTRj}, constitutes daily revenues from incremental FTRs. Daily revenues from fix transmission services are established as the total value of the fix contracts divided by the duration of the contract on a daily basis. Revenues from transmission rates are defined as the random surplus from zone A to zone B multiplied by a transmission rate. Finally, revenues from transmission rights are the price difference between the two ends of the line multiplied by the incremental FTRs. Consequently, Equation (26) can be written as

$$R_j = FTC_j + TR \times MWh_j^{daily} + FTR \times \Delta P_j^{daily} \tag{27}$$

where FTC_j is the daily revenues from firm contracts. TR is a transmission rate, and MWh_j^{daily} is the daily contribution of transmission customers located in zone B to the random surplus from zone A to zone B. FTR are the FTRs allocated to the transmission developer(s), and ΔP_j^{daily} is the average price difference between both ends of the line settled on a daily basis. Note that daily revenues from FTRs can be settled by summing over 24 hours of the hourly LMP price difference between the two ends of the line. The model can also be expressed in annual terms as shown in (28)

$$\begin{aligned}\sum_{j=1}^{365} Rj &= \sum_{j=1}^{365}\left(FTC_j + TR \times MWh_j^{daily} + FTR \times \Delta P_j^{daily}\right) \\ &= FTC_A + TR\sum_{j=1}^{365} MWh_j^{daily} + FTR\sum_{j=1}^{365}\Delta P_j^{daily} \\ &= FTC_A + TR \times MWh_i + FTR \times \Delta P_i\end{aligned} \tag{28}$$

where

FTC_A	:	Annual revenues from firm services
TR	:	Transmission rate
MWh_i	:	Sum of daily MWh_j^{daily}
FTR	:	Incremental FTRs
ΔP_i	:	Sum of daily ΔP_j^{daily}

Note that MWh_i and ΔP_i are random variables. Due to the random nature of revenues, the total revenues to transmission provider(s) are uncertain. As a result, the expected net present value of the total revenues over the cost recovery period can be written as:

$$\begin{aligned}E\langle NPV(TR)\rangle &= E\left\langle \sum_{i=1}^{RP}\frac{FTC_A}{(1+r)^i} + \sum_{i=1}^{RP}\frac{TR \times MWh_i}{(1+r)^i} + \sum_{i=1}^{RP}\frac{FTR \times \Delta P_i}{(1+r)^i} - K\right\rangle \\ &= \sum_{i=1}^{RP}\frac{\overbrace{FTC_A}^{\substack{\text{Annual revenues}\\ \text{from firm contracts}}}}{(1+r)^i} + \sum_{i=1}^{RP}\frac{\overbrace{TR \times E\langle MWh_i\rangle}^{\substack{\text{Annual expected}\\ \text{revenues from}\\ \text{transmission rate}}}}{(1+r)^i} + \sum_{i=1}^{RP}\frac{\overbrace{FTR \times E\langle \Delta P_i\rangle}^{\substack{\text{Annual expected}\\ \text{revenues from}\\ \text{transmission rights}}}}{(1+r)^i} - K\end{aligned} \tag{29}$$

where RP, the upper limit for the summations, is the cost recovery period in years, r is the annual discount rate, and K is the capital investment.

Consider a transmission customer located in zone B. The expected present value *of the total payments of the transmission customer* once the MTP is in commercial operation is defined by three terms:

1. Expected annual energy payments that are established by LMPs and energy consumption.
2. Expected annual capacity payments that are defined based on the capacity requirements by the electricity market.
3. Expected payments to transmission developer that are based on the transmission rate.

Other payments such as network transmission services, ancillary services, etc., are ignored in this research because they are not considered significant for the proposed study. Consequently, the expected present value of the total payments of the customer *j* is given by:

$$E\left\langle PV_j^{MT}\right\rangle = \sum_{i=1}^{RP} \overbrace{\frac{E\left\langle EP_{ji}^{MT}\right\rangle}{(1+r)^i}}^{\substack{Expected\\Annual\\Energy\\Payments}} + \sum_{i=1}^{RP} \overbrace{\frac{E\left\langle CP_{ji}^{MT}\right\rangle}{(1+r)^i}}^{\substack{Expected\\Annual\\Capacity\\Payments}} + \sum_{i=1}^{RP} \overbrace{\frac{TR\times E\left\langle MWh_i\right\rangle \times LDF_j \times C_2/C}{(1+r)^i}}^{\substack{Expected\\Payments\ to\\transmission\\developer}} \qquad (30)$$

Here, the superscript *MT* denotes these payments that are made after the transmission line in operation, and the subscript *j* denote the transmission customer. EP_{ji}^{MT} denotes the annual energy payment of a transmission customer. Similarly, CP_{ji}^{MT} indicates annual capacity payments. The last term of (30) corresponds to the payments to transmission developer based on the proposed transmission rate, *TR*. Recall that *C* denotes the total transmission line capacity. Assume that the capacity reserved for non firm services is denoted as C_2. Hence, C_2/C is the fraction of the transmission line capacity that is used by the random surplus. *LDF* is the Load Distribution Factor that establishes the contribution of a customer to the power flow of the merchant line. The ratio C_2/C, the load distribution factor LDF_j, and the expected value of total MWh_i establish the customer's contribution to the annual random surplus from zone A to zone B. Observe that the random annual surplus in *MWh* is approximated by the product of C_2/C and the total power flow from A to B, MWh_i. In summary:

EP_{ji}^{MT}	:	Annual energy payment in the presence of the merchant line
CP_{ji}^{MT}	:	Annual capacity payments in the presence of the merchant line
LDF_j	:	Load distribution factor
C_2/C	:	Fraction of the transmission line capacity uses by random surplus

Consider the case where zone A and zone B are not interconnected by a transmission line. The expected present value of the total payments of a transmission customer that is located in zone B is defined by:

$$E\left\langle PV_j^{NMT}\right\rangle = \sum_{i=1}^{RP} \overbrace{\frac{E\left\langle EP_{ji}^{NMT}\right\rangle}{(1+r)^i}}^{\substack{Expected\\Annual\\Energy\\Payments}} + \sum_{i=1}^{RP} \overbrace{\frac{E\left\langle CP_{ji}^{NMT}\right\rangle}{(1+r)^i}}^{\substack{Expected\\Annual\\Capacity\\Payments}} \tag{31}$$

Here, the superscript *NMT* indicates that there is not a transmission line between zone A and zone B. Only two terms defined the expected payments: 1) Annual energy payments, and 2) annual capacity payments. Payments to transmission developers are not considered due to the fact that there is not a transmission line to connect the two zones.

Based on (30), (31), and the assumption considered in section I, the transmission rate can be obtained from the following optimization problem:

$$\begin{aligned}
&\max_{TR} \quad E\left\langle NPV(TR)\right\rangle \\
&s.t \\
&E\left\langle PV_j^{MT}\right\rangle \leq E\left\langle PV_j^{NMT}\right\rangle \quad \forall j = 1\ldots N \\
&CVaR_\beta\left(-NPV(TR)\right) \leq \delta \\
&TR > 0
\end{aligned} \tag{32}$$

The cost function of (32) corresponds to the expected net present value collected by the transmission developer defined by (29). N is the number of transmission customers designated to pay for the merchant project. The left hand side of a constraint of (6) is the total payments once the project is in commercial operation, whereas the right hand side is the payments in the absence of the merchant line. Note that the inequality guarantees that transmission customers located in B realize the benefits from the project. Finally, $CVaR$ assures that the net present value is maximized with a certain confident level.

4.3 Solution Method

Suppose initially that all future values of the random variables are known, i.e., the future values of $MWh_i, \Delta P_i, EP_{ji}^{MT}, CP_{ji}^{MT}, EP_{ji}^{NMT}, CP_{ji}^{NMT}$ can be forecasted accurately. Under this condition, the objective function can be rewritten as

$$E\langle NPV(TR)\rangle = NPV(TR) = \sum_{i=1}^{RP}\frac{FTC_A}{(1+r)^i} + \sum_{i=1}^{RP}\frac{TR\times MWh_i}{(1+r)^i} + \sum_{i=1}^{RP}\frac{FTR\times\Delta P_i}{(1+r)^i} - K \qquad (33)$$

Note that the only variable is *TR* so that (33) corresponds to a straight line that is shown in Fig. 19. The slope of the line is given by $\sum_{i=1}^{RP}\left(MWh_i/(1+r)^i\right)$ and the y-intercept by $\sum_{i=1}^{RP}\left(FTC_A/(1+r)^i\right)+\sum_{i=1}^{RP}\left(FTR\times\Delta P_i/(1+r)^i\right)-K$. It has been shown that revenues from transmission rights are not sufficient for recovery of the capital investment. Thus, in the absence of revenues from firm contracts (FTC_A) and transmission rate (*TR*), the y-intercept would be negative. The lower straight line represents such a case. The higher straight line corresponds to a case where the y-intercept is positive due to the presence of firm contracts.

The vertical line is a constraint of (32) when it is rearranged as the inequality (34). Observe that there are *N* different vertical lines. Each line represents a different transmission customer. The constraint with the lowest right hand side value defines the *feasible values* of *TR*.

$$TR \le \frac{\sum_{i=1}^{RP}\frac{\left(EP_{ji}^{NMT}-EP_{ji}^{MT}\right)}{(1+r)^i}+\sum_{i=1}^{RP}\frac{\left(CP_{ji}^{NMT}-CP_{ji}^{MT}\right)}{(1+r)^i}}{\sum_{i=1}^{RP}\frac{MWh_i\times LDF_j\times C_2/C}{(1+r)^i}} \qquad (34)$$

The optimal transmission rate TR^* is established by the intersection of the leftmost vertical line and the straight line. Equation (35) shows the optimal value assuming that customer k has the lowest right hand value of (34).

$$TR^* = \frac{\sum_{i=1}^{RP} \frac{\left(EP_{ki}^{NMT} - EP_{ki}^{MT}\right)}{(1+r)^i} + \sum_{i=1}^{RP} \frac{\left(CP_{ki}^{NMT} - CP_{ki}^{MT}\right)}{(1+r)^i}}{\sum_{i=1}^{RP} \frac{MWh_i \times LDF_k \times C_2 / C}{(1+r)^i}} \qquad \textbf{(35)}$$

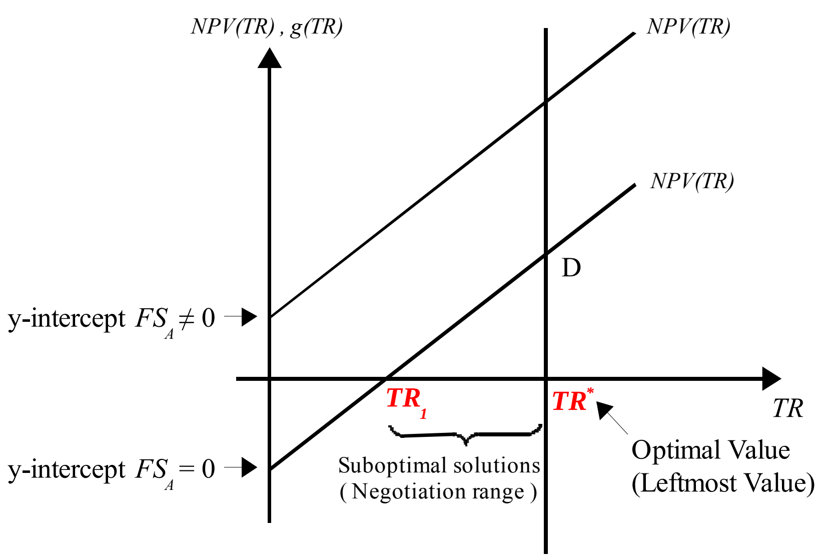

Figure 19. A graphical interpretation of equation (35)

The optimal value TR* have the following important implications:

1. Maximize the net present value of the future revenues for transmission investors.
2. The optimal value TR* is established by one transmission customer that does not derive benefit from the merchant project for reason that the merchant transmission

project does not change the total payments. As mentioned, that customer corresponds to the leftmost vertical line in Fig. 19. The rest of transmission customers do receive benefits from the project since the total payments, once the line is in operation, are less than in the absence of the transmission line. However, the customer that does not obtain a direct benefit might be willing to pay for the project since energy price and capacity price might be less volatile once the new project is in operation.

3. According to Fig. 19, values of the transmission rate between $\left[TR_1, TR^*\right)$ are sub-optimal solutions. This range of values can be considered as **negotiation range**. These values guarantee that all transmission customers derived economic benefits (savings) and the present value of the revenues is higher than the capital investment. Observe that the negotiation range provides wider incentives to transmission developers and hence can be attractive to investors.

Consider a nondeterministic case. Future values of the random variables are unknown. Define the loss function as the negative of *NPV(TR)*. For this case, the optimization problem (32) provides a transmission rate for which the expected net present value is maximized and the losses do not exceed a threshold level δ within a confidence interval defined by β.

Define a vector y as one that contains all random variables, i.e., the annual *MWh* and annual ΔP for every year. Recall that RP denotes the cost recovery period in years. Therefore, the vector y has $2 \times RP$ components since every year has two random variables. The probability that the losses do not fall bellow a threshold α is given by

$$\psi(TR,\alpha) = \int_{-NPV(TR,y)\leq\alpha} p(y)dy \tag{36}$$

where *p(y)* is the joint probability distribution function of the random vector *y*. The *β-VaR* and *β-CVaR* for a specified probability level *β* are denoted by $\alpha_\beta(TR)$ and $\phi_\beta(TR)$ respectively, and defined by:

$$\alpha_\beta\left(TR\right) = \max\left\{\alpha \in R : \psi(TR,\alpha) \leq \beta\right\} \tag{37}$$

$$\phi_\beta\left(TR\right) = \frac{-1}{1-\beta} \int_{-NPV(TR,y)\geq\alpha_\beta(TR)} NPV\left(TR,y\right) p\left(y\right) dy \tag{38}$$

Equation (37) is the right endpoint such that $\psi(TR,\alpha) = \beta$, i.e., the probability that the *-NPV(TR,y)* is equal to *β*. Equation (38) is the conditional expectation given that the losses are greater than $\alpha_\beta\left(TR\right)$. According to [46]-[47], *β-CVaR* (equation (38)) can be characterized by a function $F_\beta(TR,\alpha)$ as follows:

$$F_\beta\left(TR,\alpha\right) = \alpha + \frac{1}{1-\beta} \int_{y\in R^m} \max\left(-NPV\left(TR,y\right) - \alpha, 0\right) p\left(y\right) dy \tag{39}$$

where m is the number of random variables. *β-CVaR* corresponds to the minimum value of $F_\beta(TR,\alpha)$ as indicated by[1]:

$$\phi_\beta\left(TR\right)=\min_{\alpha} F_\beta\left(TR,\alpha\right) \tag{40}$$

Equation (39) can be simplified by sampling the distribution *p(y)*. Assume that the following sampling from *p(y)* is available

$$p(y_1), p(y_2), \ldots, p(y_M) \tag{41}$$

The corresponding approximation of (39) is given by

$$\tilde{F}_\beta\left(TR,\alpha\right)=\alpha+\frac{1}{M\left(1-\beta\right)}\sum_{i=1}^{M}\min\left(-NPV\left(TR,p_i\left(y\right)\right)-\alpha,0\right) \tag{42}$$

Based on (42), the optimization can be formulated as a linear optimization problem as follows:

---

[1] See [46] for the mathematical proof.

$$
\begin{aligned}
&\max_{TR,\alpha} \quad E\langle NPV(TR)\rangle \\
&s.t \\
&E\langle PV_j^{MT}\rangle \le E\langle PV_j^{NMT}\rangle \quad \forall j = 1\ldots N \\
&\alpha + \frac{1}{M(1-\beta)}\sum_{i=1}^{M} u_i \le \delta \qquad \forall i = 1\ldots M \\
&u_i \le -NPV\left(TR, p\left(y_i\right)\right) - \alpha \quad \forall i = 1\ldots M \\
&u_i \ge 0 \\
&TR > 0
\end{aligned}
\tag{43}
$$

Note that the joint distribution of y is not required. The linear optimization problem only requires a sampling from the distribution.

4.4 Numerical Results

Consider the two-zone system that is shown in Fig. 20. Zone B has four transmission customers (or sub – zones) that derive the economic benefits from the merchant project. Assume that the merchant transmission line is a 230KV transmission line with a nominal capability of 1000MW. The cost per mile for this new line is assumed to be \$ 550,000/ mile, and the length of the line is 200 miles. The total capital investment is therefore \$ 110,000,000.

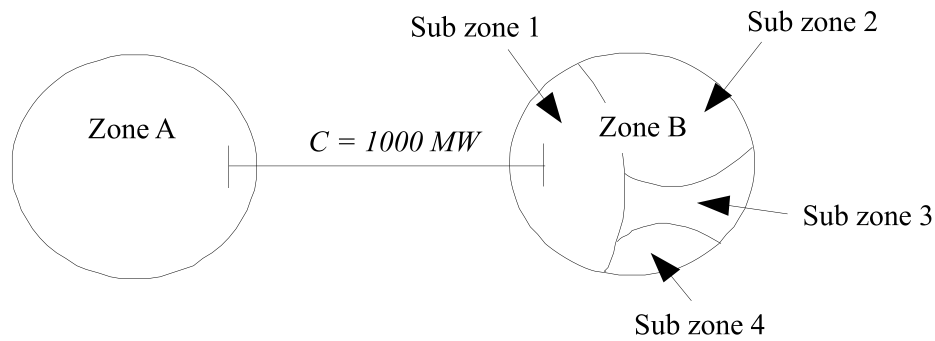

Figure 20. A two-zone system

Assume that sub-zone 4 subscribes to a firm contract with the transmission developer that allows cheaper energy to be imported from zone A. It was mentioned that a firm contract guarantees a deterministic cash flow to the provider. Since sub–zone 4 is paying for the transmission project via a firm contract, it is not considered in the calculation of transmission rates.

Table 1 shows the assumed annual energy and capacity payments for the three sub–zones and the expected annual increments in the absence of the merchant line. On the other hand, table 2 shows the estimated and the increments once the merchant line is in operation. Note that all the payments in table 2 are lower than those in table 1. For simplicity, it is assumed that the annual increments are the same in the absence or presence of the transmission line even though the methodology allows different increments. Observe that the payment reduction is an incentive for construction of a merchant line.

The deterministic case is analyzed first. Assume that the firm contract recovers 40% of the total capital investment, i.e., \$ 44,000,000.00. Revenues from financial transmission rights are assumed to recover 30% of the capital investment. This assumption relies on the fact that FTRs can not be used to fully recover the investment. However, this assumption will be relaxed in order to analyze the impact on FTRs over the transmission rate.

Table 1. Estimated annual payments and increment in the absence of a merchant line

	Absence of merchant transmission line			
	Estimated annual payments		Estimated Annual increment	
	Energy payments	Capacity payments	Energy payments	Capacity payments
Sub zone 1	$ 6,000,000	$ 713,000	3 %	2 %
Sub zone 2	$ 2,500,000	$ 158,000	1 %	1 %
Sub zone 3	$ 5,000,000	$ 557,000	2 %	2 %

Table 2. Estimated annual payments and increment in the presence of a merchant line

	Presence of merchant transmission line			
	Estimated annual payments		Estimated Annual increment	
	Energy payments	Capacity payments	Energy payments	Capacity payments
Sub zone 1	$ 5,400,000	$ 640,000	3 %	2 %
Sub zone 2	$ 2,375,000	$ 150,000	1 %	1 %
Sub zone 3	$ 4,500,000	$ 500.000	2 %	2 %

The load distribution factors of sub-zones 1, 2, 3 are, respectively, 0.10, 0.05, and 0.30. Note that sub-zone 3 is responsible for 30% of the total flow from zone A to zone B, whereas sub-zone 2 has the lowest contribution.

Two different values for the expected line utilization for the random component are considered: 40% and 60%, i.e., on average, the random surplus will use 40% or 60% of the non-firm capacity. With the estimated payments, the load distribution factors, and a discount rate of 9%, the transmission rate can be found based on (35) for different value of non-firm capacity. The results are shown in Fig. 21.

The horizontal axis represents non-firm line utilization as a percentage of line capacity. For instance, a value of 0.4 indicates that 400 MW (40% of *C*) is utilized by non-firm service, whereas 600 MW (60% of *C*) is reserved for firm services. The vertical axis represents transmission rate values. The upper curve corresponds to the values whether the expected line utilization of non-firm service is 40%. Note that a lower expected line utilization by non-firm capacity is compensated with a higher transmission rate. In other words, the 30% that needs to be recovered by the transmission rate is affected inversely by the expected value of line utilization, i.e., high expected utilization reduces the required transmission rate as indicated by Fig. 21.

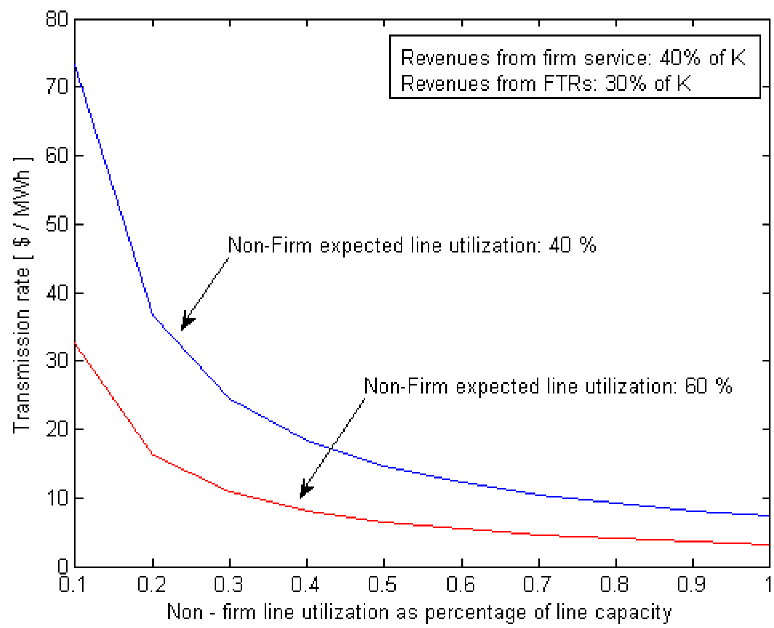

Figure 21. Transmission rate for different value of non firm capacity

Suppose that the expected annual non firm utilization is not constant, i.e., the expected annual power flow through the line changes over time.

The capacity of a transmission line is designed taking into account the fact that demand increases over time, i.e., some capability is left for future power flow increment. As a consequence, the expected annual power flow through the line increases as time goes on. The upper right corner of Fig. 22 shows a hypothetical annual expected power flow over the cost recovery period. It is expected that the line becomes congested once the power flow reaches the maximum transmission line capability. Congestion is a market signal. It increases prices, and hence facilitates new generation. Once new generation capacity is installed in zone B, it may not be necessary to import energy from zone A, and therefore power flow through the line is expected to decrease. The upper figure on Fig. 22 depicts such a behavior. Note that the annual expected non firm utilization is therefore not constant over the cost recovery period.

Suppose that the power flow increases 5% annually. The line remains congested for 5 years, and the power flow decreases 5% annually. Fig. 22 shows the transmission rate for that scenario. The curve is compared with the two curves given in Fig. 21. Note that a variable expected non firm utilization leads to results similar to those from a constant expected value of 60%. This suggests that a constant expected value can accurately approximate the value of the transmission rate. This reduces the computational effort required for the calculation of variable expected power flow. However, an inaccurate estimation of the constant expected value can cause an overestimate of the transmission rate as shown by the upper curve in Fig. 22. Hence, the constant expected value must be identified in order to obtain accurate results.

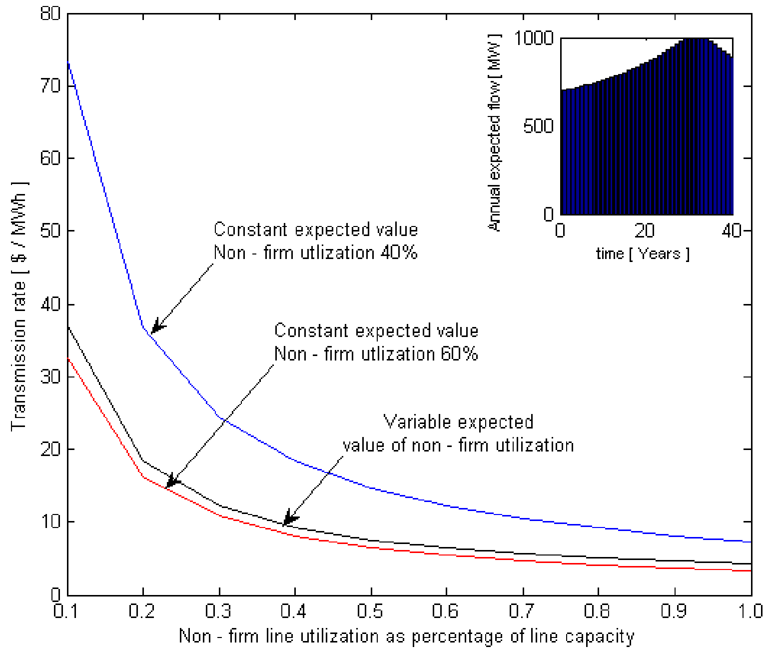

Figure 22. Transmission rate for variable expected value of non firm utilization

According to (35), the transmission rate shown in Fig. 21 is the upper limit of the negotiation range. Savings for all sub-zones are realized for lower values. However, the upper limit does not guarantee that the investment can be recovered. Fig. 23 shows the net present value, for the deterministic case, for different values of *TR* and non-firm line utilization. The figure on the left side shows a cutting plane that divided the net present value surface. The upper part, as shown in the figure, corresponds to positive values of the *NPR*, whereas the lower part represents the negative values. The figure on the right hand side shows the breakeven curve on the plane defined by the transmission rate and non-firm line utilization, i.e., it is the projection of NPV on that plane. The upper right area is the values that recover the capital investment, while the lower left values represents losses for the investor.

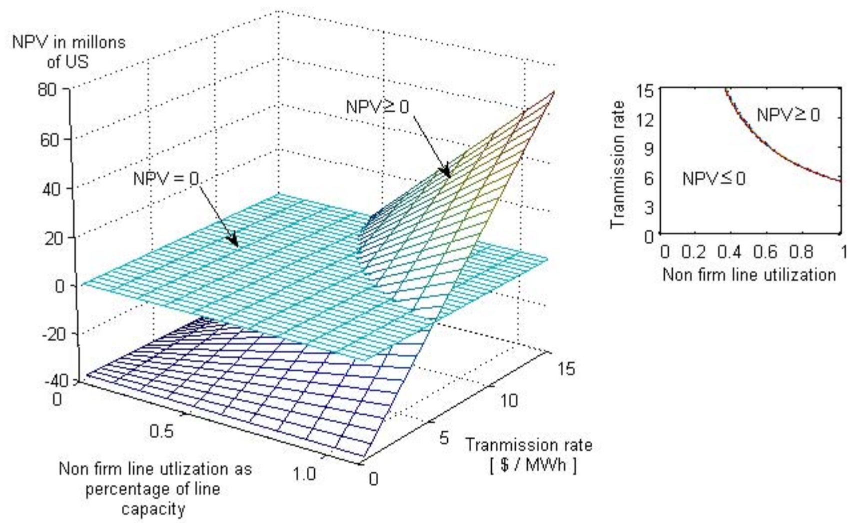

Figure 23. Net present value as function of transmission rate and non firm capacity

The negotiation range can be established using Fig. 21 (or Fig. 22) and Fig. 23. Recall that Fig. 21 provides the upper limit whereas Fig. 23 provides a breakeven curve for the net present value. Consider that the transmission provider subscribes to a firm contract with sub-zone 4 that reserves 40% of the capacity and recovers 40% of the capital investment. As a consequence, 60 % of the line is used by non-firm services. Assume also that revenues from transmission rights are 20 % of the capital. Figure 24 shows the negotiation range for that situation. The horizontal line is the upper limit of the transmission rate from Fig. 21, i.e., *TR = 12.25 $ / MWh*. The lower value is defined by the upper curve. Note that a value that belongs to that negotiation range represents savings for all sub-zones. Figure 24 also shows the effect of FTRs revenues on the negotiation range. The upper limit is not affected by the

FTRs according to (35). However, the lower limit changes as shown in Fig. 24. It is observed that higher revenues from FTRs increase the negotiation range.

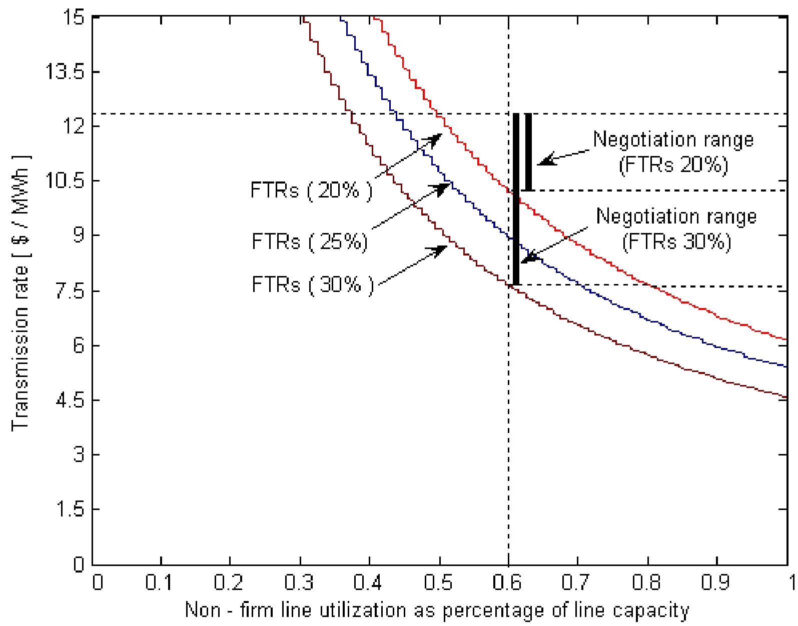

Figure 24. Negotiation range for a deterministic case

Suppose that the investor sets the maximum loss for the net present value as 5% of the capital investment, i.e., $ 5,500,000.00. The confidence level is set by the investor to be 95 %. It means that, 95 % of the time, the losses (net present value) should not exceed $ 5.5 millions. Based on these considerations, Fig. 25 shows the transmission rate obtained by (43) . Different values of the net present value are generated randomly to simulated future uncertainties. Note that the optimal values obtained by the optimization problem are lower that the deterministic values. This result confirms the intuition that investors need to be more conservative if losses are to be kept within a certain confidence level. As a consequence of the lower values, the negotiation range is reduced, which is shown in Fig. 26.

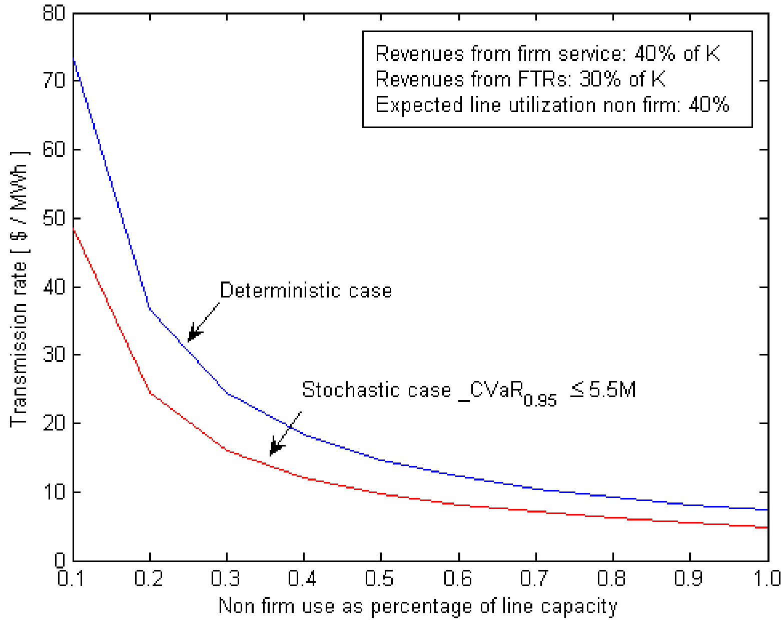

Figure 25. Transmission rate for different value of non firm capacity: Stochastic case

Two cases are considered in Fig. 26. First, consider the case where an investor firms a contract that reserves 40 % of the line and recovers 40 % of the capital using firm services. The lower breakeven curve corresponds to a case where FTRs recover 30 % of the line. The negotiation range is highlighted in Fig. 26 that is smaller than the range shown in Fig. 24. Second, consider that revenues from FTRs recover 20 % of the capital. Note that the negotiation range is in the infeasible area (negative values of NPV). Hence, it is evident that uncertainty needs to be included in the calculation of transmission rates since Fig. 24 shows that under the same circumstance the negotiation range is feasible.

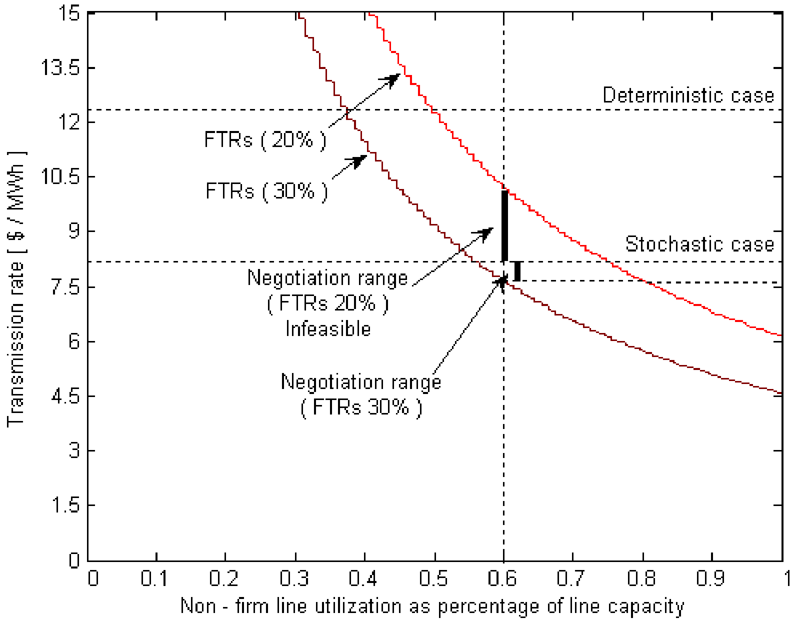

Figure 26. Negotiation range stochastic case

CHAPTER 5. INTERACTION BETWEEN POWER PLANT INVESTMENT AND TRANSMISSION INVESTMENT: A CONCEPTUAL FRAMEWORK

5.1 Problem Formulation

An extended approach to evaluate of merchant transmission investments is presented in this section. Consider the merchant transmission project shown in Fig. 26. It was mentioned that a merchant transmission project as a market driven solution is used to bring cheaper energy from inexpensive generators. Cost recovery of merchant projects, at least in theory, would be from those who benefit from the cheaper energy. Two LSEs are shown in Fig. 26 as direct beneficiaries of the merchant project, i.e., LSE_1 and LSE_2. Note that LSE_1 and LSE_2 might not be affiliated with the project developer.

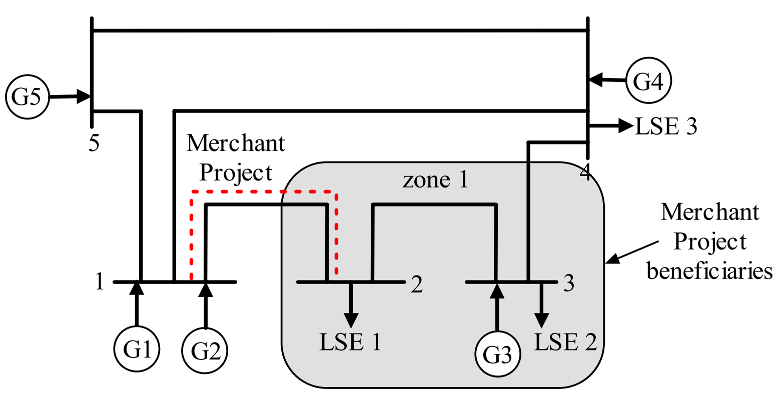

Figure 27. A merchant project in a 5 bus system

A transmission investment decision is based primarily on the perceived energy savings of LSE1 and LSE_2 and the payment from them to the project developer. The present value of the future expected cash flow (payments from LSEs) establishes the value of the project. However, in a deregulated environment, it is difficult to provide an accurate revenue forecast due to the high volatility of energy prices. Therefore, revenues from the energy market are uncertain and, as a result, *the value of the project* is also uncertain.

Strategic interaction among different participants also increases uncertainty during the decision making process. Consider two investors: A merchant transmission developer (MTD) and a generator developer (GD) who are willing to invest in the power system showing in Fig 26. Whether GD decides to invest in zone 1 is a crucial factor to MTD's decision, i.e., a new generation at bus 2 or 3 changes energy prices and, therefore, revenues from the market to the merchant transmission developer.

A merchant transmission project or generator project evaluation must take into account uncertainty of future cash flow and uncertainty of others' decision as part of the decision making process. When all these elements are incorporated into the financial analysis, more accurate project evaluation is achieved.

Note that a merchant transmission project and a new generation project share the following characteristics:

1. Future revenues from the energy market are stochastic.
2. The investment decision is irreversible.
3. Developers have no obligation to build. In other words, the investment can be delayed until favorable economic conditions arise.
4. MTD's decision affects GD's decision and vice versa.

Real options and game theory are two techniques that are used to evaluate projects under uncertainty and strategic interaction. Real options take into account uncertainty over future revenues, irreversible investments and time delay (characteristics 1, 2 and 3). On the other hand, game theory is a common technique where interactions between investors are considered (characteristic 4). When real options and game theory are combined, a better project evaluation along with an investment strategy is achieved in which all the above-mentioned characteristics can be considered.

Game theory has been widely used to study strategy interactions among competitors. In this research, the theory allows evaluating *different strategies*, i.e., various investment strategies can be analyzed when benefits of each strategy depends on the choices of other investors. Consider the follow simultaneous game in which MTD and GD (game players) are involved. Two strategies are considered for each player, i.e., invest (1) or defer (2). The payoffs matrix is shown in Fig. 27. The pair value $\left(\pi_{ij}^{MTD}, \pi_{ij}^{GD}\right)$ represents the expected revenues of the MTD and GD, respectively. Subscripts are used to represent the strategy. For instance, $\left(\pi_{12}^{MTD}, \pi_{12}^{GD}\right)$ denotes the expected revenues when MTD chooses to invest, and GD chooses to defer. Each pair value of revenues is calculated based on the expected revenues of the chosen strategy. The extensive form representation of the game is illustrated in Fig. 28. The dashed line represents a simultaneous game.

		Generator developer (GD)	
		Invest	Defer
Merchant Transmission developer (MTD)	Invest	$\left(\pi_{11}^{MTD}, \pi_{11}^{GD}\right)$	$\left(\pi_{12}^{MTD}, \pi_{12}^{GD}\right)$
	Defer	$\left(\pi_{21}^{MTD}, \pi_{21}^{GD}\right)$	$\left(\pi_{22}^{MTD}, \pi_{22}^{GD}\right)$

Figure 28. Normal form representation of a simultaneous game

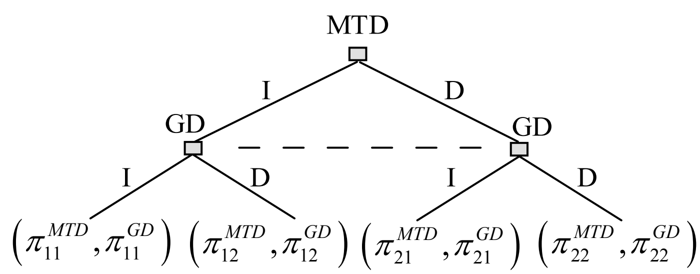

Figure 29. Extensive form representation of a simultaneous game

Suppose that MTD and GD face a simultaneous game at T_0. Three different scenarios could arise, namely:

1. Nash equilibrium is reached when MTD and GD decide to invest, and hence the game is over.
2. Either player can invest. The investor (MTD or GD) becomes the leader and the other player is then the follower. The follower will make the decision (invest or delay) based on future electricity market conditions and knowledge of the leader's decision. Although the leader's decision is already known, revenues from the energy market

are still uncertain. Game theory provides a way to take into account uncertainties. A third player, called Nature and denoted as N, enters the game. Nature represents uncertainties from the energy market. Nature can move the game up or down. The game is moved up when the energy market offers favorable economic conditions to the follower, i.e., higher expected revenues. When economic conditions are unfavorable, the game is moved down.

3. MTD and GD decide to delay the investment. Nature subsequently moves the game up or down, and a simultaneous game is played again at a future time T1.

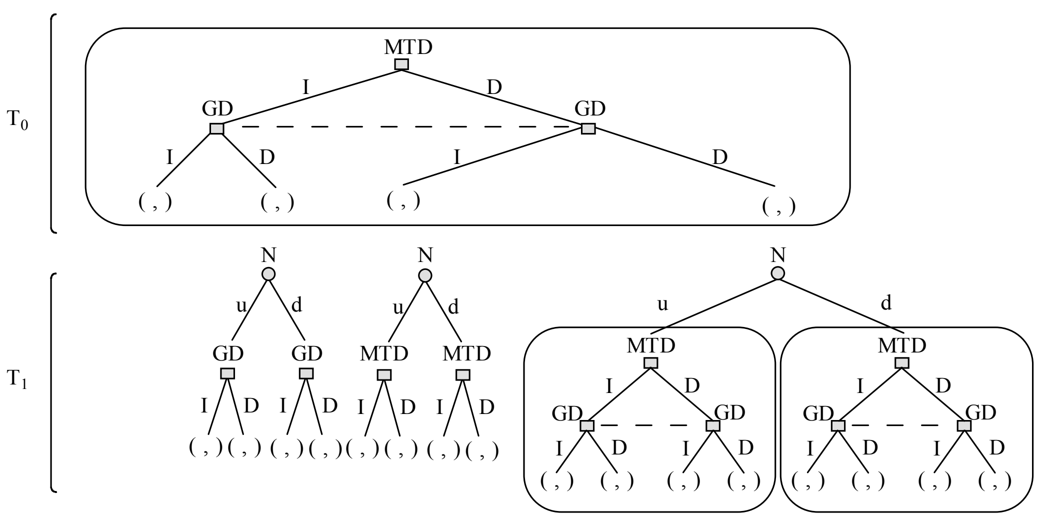

Figure 30. The game in extensive form

Figure 29 summarizes all possible outcomes of the game for a two period game (T_0 and T_1). Each pair of parentheses represents the total revenues at different stages of the game. Note that revenues at T_0 depend on the different outcomes of the game at T_1. Real option theory provides a way to compute *the value of the project* at T_0 having the project value at T_1.

In other words, the final investment decision depends on the total values at T_0 that are established working backward from T_1, i.e., values at T_1 are discounted using risk-neutral probabilities, established by real option theory, and a risk free discount rate. As a consequence of discounted future values using risk-neutral probabilities, the value of the project implicitly includes the value of the option to invest. The project value at T_0 is thus more accurate when it is compared with other capital budgeting techniques.

Given that Nash equilibrium specifies a set of strategies where no investor has an incentive to change unilaterally, it indicates the investment decision that investors should make at T_0. Additionally, Nash equilibrium is an indicator to policy-makers to better understand investors' behavior and market incentives. For instance, a monopolistic outcome indicates that either MTD or GD has invested, and there is not further incentive for any additional investor to enter the market. This situation might lead to market power and thus a decrement of social welfare. Different market incentives might change the equilibrium and therefore promote more investments.

5.2 Numerical Approach

Consider the power grid shown in Fig. 26. Revenues collected by the developer come from the market. Specifically, the merchant transmission project revenues are based on energy savings of LSE_1 and LSE_2 once the project is in commercial operation. On the other hand, generators' revenues are established according to the marginal price at generator's location.

Consider the following cases:

Case 1: The base case as shown in Fig. 26. Neither new project is in commercial operation.

Case 2: The base case including a new merchant project. The merchant project connects bus 1 and bus 2.

Case 3: The base case including a new generation at bus 2.

Case 4: The base case including a new generation at bus 2 and a new merchant project which connects bus 1 and bus 2.

Locational marginal prices are calculated for each case over a year. System data are found in [43]. Monthly average marginal prices are considered instead of hourly marginal prices, i.e., an optimal DC power flow is computed having a nodal demand equal to the average monthly demand. Generation costs are assumed constant, and contingencies are not considered over the year.

The annual savings for LSE_1 *or* LSE_2, denoted as C_{MD} (*C*ash to *M*erchant *D*eveloper), once the merchant project is in commercial operation and, if capacity payments are ignored, are given by:

$$C_{MD} = \sum_{i=1}^{12} \left(LMP_i^{C_1} - LMP_i^{C_2} \right) \times MWh_i \times \left(1 + r/12 \right)^i \tag{44}$$

where

$LMP_i^{C_1}$	:	Month *i* average marginal price for case 1 at LSE location.
$LMP_i^{C_2}$	:	Month *i* average marginal price for case 2 at LSE location.
MWh_i	:	Monthly energy consumption for month *i*

r : Annual discount rate

Note that C_{MD} corresponds to the future value of annual savings. The *total* expected payment from LSE_1 and LSE_2 to MTD is the sum of savings of LSE_1 and LSE_2. Similarly, annual revenues, denoted as C_{GD} (*C*ash to *G*enerator *D*eveloper), once the new generation is in commercial operation, are given by

$$C_{GD} = \sum_{i=1}^{12} LMP_i^{C_3} \times MWh_i \times (1 + r/12)^i \quad (45)$$

where $LMP_i^{C_3}$ corresponds to the average monthly marginal price for month *i*, case 3, at generator location, and MWh_i denotes the monthly energy generated by the generator.

Annual cash flow when a merchant project and generator project are both in commercial operation can also be obtained from (44) and (45). In such case, $LMP_i^{C_2}$ and $LMP_i^{C_3}$ are replaced by $LMP_i^{C_4}$ in (44) and (45) respectively.

Having C_{GD} or C_{MD}, total revenues *R* is the present value of a growing annuity over the cost recovery period, specifically:

$$R = C \times \left(\frac{1}{r-g} - \frac{1}{r-g} \left(\frac{1+g}{1+r} \right)^t \right) \quad (46)$$

where

R : Total revenues
C : Annual cash inflow. *C* corresponds to C_{GD} (equation 8) or C_{MD} (equation 9)
g : Growing rate
t : Cost recovery period

Annual revenues are assumed to grow at a constant rate *g* for this numerical example. A steady load increment over time is expected to produce more congestions. As a consequence, it is projected that the difference of LMPs (equation (45)) and LMPs (equation (46)) grows over time and hence revenues from the market to developers also increase. This assumption will be discussed in the next steps of this research.

Assume that all demands (LSE_1, LSE_2, and LSE_1) have a steady increment of 3% from T_0 to T_1, i.e., for 3 years. It is also assumed that the growing rate may change to 5% or 1% at T_1, i.e., Nature (N) inserts an uncertainty about the future growing rate and hence future revenues. Table 3 shows the present value of expected cash flow over 30 years at $T_{1.}$ They are derived from equations (44), (45) and (46). Note that there are not revenues when MTD and GD defer the investment decision. However, a different value might be obtained when total payoffs are established using option theory, i.e., although the merchant project or generation project are not generating revenues, the option to invest (defer the investment decision) can have a positive value. Payoffs using option analysis and reaction functions will be explored in further steps of this research.

Table 3. MTD and GD Revenues at T1

Scenario		Nature	Merchant Transmission Developer (MTD) Revenues	Generator Developer (GD) Revenues
MTD Decision	GD Decision			
Defer	Defer	u=5%	$ 0.00	$ 0.00
Defer	Invest		$ 0.00	$ 1,649,835.00
Invest	Defer		$ 1,985,686.00	$ 0.00
Invest	Invest		**$ 499,703.00**	**$ 1,392,922.00**

Defer	Defer	d=1%	$ 0.00	$ 0.00
Defer	Invest		$ 0.00	$ 2,426,118.00
Invest	Defer		$ 2,919,995.00	$ 0.00
Invest	Invest		**$ 734,824.00**	**$ 2,048,323.00**

Different values at T_0 (Fig. 29) when MTD and GD defer the investment is found using binomial approach where the state value of each node at T_1 corresponds to Nash equilibrium for $u=5\%$ and $d=1\%$. Nash equilibria are shown in bold face in table 4.

Assuming a risk free rate of $r=10\%$ and a risk-neutral probability of $p=0.4$, the present value at T_0 is given by:

$$
\begin{aligned}
C_{MTD} &= \frac{pV_{MTD}^{+} + (1-p)V_{MTD}^{-}}{1+r} = \frac{0.4\times 499,703 + (1-0.4)\times 734,819}{1+0.1} = 582,520 \\
C_{GD} &= \frac{pV_{GTD}^{+} + (1-p)V_{GTD}^{-}}{1+r} = \frac{0.4\times 1,392,922 + (1-0.4)\times 2,048,323}{1+0.1} = 1,623,800
\end{aligned}
\qquad (47)
$$

Table 4 presents the payoffs at T_0. Note that the values when MTD and GD postpone the investment correspond to equation (47). Payoffs for other strategies are the present value of the expected cash flow –equations (44), (45) and (46)– for a growing rate of 3%. Given that no reaction function is considered, revenues when GD or MTD postpone the investment and the other player invests are zero. The reaction function provides a way to evaluate the project at T_1 and therefore has a non-zero value at T_0.

Table 4. MTD and GD Revenues at T0

		GD	
		Invest	Defer
MTD	Invest	**($ 537776.00 , $ 1593340.00)**	($ 1508551.00 , $ 0.00)
	Defer	($ 0.00 , $ 1849115.00)	($ 582520.00 , $ 1623800.00)

Nash equilibrium is reached when MTD and GD invest. However, MTD and GD are better off when both decide to defer the investment. In other words, it is possible to improve MTD and GD's rewards when MTD and GD coordinate their actions and postpone the investment.

It is noted that this hypothetical electricity market where revenues are based only on marginal prices might offer enough incentives to invest, i.e., Nash equilibrium is reached when MTD and GD invest. However, real electricity markets are more complex and might not offer sufficient incentives. The following issues need to be addressed in further steps in order to complete a more comprehensive study:

1. Reaction function: MTD and GD will react once the other player files an interconnection request. The value of the option to invest is then changed and so does the value of the project. Therefore, reaction functions have to be part of the evaluation process.
2. Cooperative game: Market administrator can encourage cooperation between different investors as a way to improve social welfare and reduce the risks of

investments. This leads to a different game where MTD and GD are more interested in cooperation than competition.

3. Existence of Nash equilibrium: A set of market incentives will be studied in order to prove mathematically the existence of Nash equilibria.

CHAPTER 6. CONCLUSION

A traditional method used by vertically integrated power utility companies in transmission investment projects is to invest now, file for regulatory approval to include the capital investment in the rate, and file for a new rate case if the previously approved rate does not generate sufficient revenues to recover the costs. In the past, this approach allows the utility to fully recover its transmission investments. However, in today's competitive industry environment, it is no longer certain that the rate case would result in a full recovery of the investment. The market structure for electric energy is fairly well set up in the U.S. power industry today. Therefore the economic signal for power plant investment is clear. In contract, the investment / return mechanism for transmission capabilities is not well established. As a result, there are insufficient economic incentives to attract investments in transmission grid expansion. This is particularly true for merchant transmission projects.

In general, investing in transmission is an irreversible decision. To avoid a failure to recover the investment in a project requires a prudent decision that relies on accurate load and revenue forecast whose accuracy improves as more information becomes available. For Merchant Transmission investment, such a waiting time is available before making an investment decision. Since there is no obligation to build and there is not a firm commissioning date to complete a merchant transmission project, a transmission investor can 1) postpone a decision until more favorable information is available and a better revenue cash flow is projected, or 2) forgo the investment decision without incurring a heavy financial penalty if the projected revenue from the newly available information shows that the investment cannot be recovered. Taking advantage of this flexibility, this dissertation presents an investment strategy that mirrors a stock option method to identify the optimal investment criterion for exercising an option to build the Merchant Transmission.

The decision process is based on a stochastic revenue model from an approved fixed transmission rate. A rate design based on 1CP methodology is used to illustrate the effectiveness of the option approach. The approach also shows that lowering the risk of not recovering the investment through added incentives (i.e. revenues from transmission rights or added initial incentives to an approved fixed transmission rate) would encourage merchant transmission investment. Finally, it is important to point out that the proposed method only provides the probability that the investment can be fully recovered for making an investment decision. It does not guarantee full recovery in actuality due to market and demand uncertainties.

A tool to help transmission investors quantify the risk of not recovering the capital investment when the option is exercised is developed. The resulting conditional probability provides additional information from which a decision to construct the project can be made. Three scenarios are analyzed in order to evaluate the impact of different suboptimal values on the conditional probability of not recovering the capital investment. A comparison with the net present value rule is performed. The results show that an early exercise of the option to build can still be profitable in the long term when future uncertainties are favorable, even though the present value of future cash flows is lower than the capital investment. The proposed risk analysis technique might also be used by regulators to determine the necessary incentives to promote transmission investment when the present value analysis shows that the project is not favorable. A constant mean and variance of the stochastic process model, Geometric Brownian Motion, is an assumption that needs to be relaxed in the future work. However, GBM is a simplification that allows, via Kolgomorov equations, a quick estimation of the transmission investment risk.

Incentives via a transmission rate are explored in this research. A novel market – driven rate is developed in order to provide additional economic incentives to developers. The design criterion is that all transmission customers derive economic benefits from the new projects and developers obtain the maximum expected value of the revenues. The rate charges all customers according to their contribution of *MWh* that flows from a zone that has a surplus of electricity to another zone that has an interest in cheaper energy. The methodology also establishes a negotiation range. The range of rates guarantees a positive net present value for the investment and savings for all investors. Numerical results suggest that this market driven mechanism along with FTRs and firm transmission services can assure that the capital investment is fully recover. Moreover, the rate is easy to implement since the power flow contribution by each transmission customer can be measured using the available technology. The rate can also be established ahead of time. The rate does not require significant changes in regulation, and hence it would be more acceptable to power utilities.

A theoretical framework is presented in which the impact of power plants investment on transmission investment is evaluated. The net present value and decision tree often over- or under-evaluated the value of the project when others' decisions are ignored. When all characteristics (strategic interaction, option to delay, uncertainty over revenues, etc.) of a merchant project are taken into account, a project can be accurately evaluated, leading to more informed decisions by the investor.

Finally, this dissertation presents a comprehensive analysis of merchant transmission projects. New concepts and techniques for the merchant transmission investment are developed that serve as a market – driven investment solution. It is believe that the proposed methods can play a significant role as the industry deals with the aging and increasingly weakened power infrastructure.

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