Cost calculation of ancillary services including system security, automatic generation control and reactive power

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COST CALCULATION OF ANCILLARY SERVICES
INCLUDING SYSTEM SECURITY, AUTOMATIC
GENERATION CONTROL AND
REACTIVE POWER

by

Mohammad Shahzad Lateef

A thesis submitted in partial fulfillment
of the requirements for the degree of

Master of Science
in
Electrical Engineering

Department of Electrical and Computer Engineering
University of Nevada, Las Vegas

May, 1997
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ABSTRACT

The recent changes in the electric utility industry due to the deregulation of the industry have created an immense need for the evaluation of all the services provided. The electric utility companies all across the United States have been providing these services for a long period of time. However, under the light of current deregulation, each one of these services have to identified and evaluated separately. This thesis discusses three of these services, including security of the power system operation (Spinning and operating reserves), Automatic Generation Control (Load Following) and reactive power support. These three services are vital in operation of any power system. There is a lot of research currently being done to evaluate the cost of providing these services. The thesis makes an attempt to recognize the importance of these services and uses the system dispatch and unit commitment theory and principles to evaluate the cost of each of the above mentioned services.
CHAPTER 1:

INTRODUCTION

The electric power industry is today an industry in transition. In response to changes in the law, technology, and markets, competitive pressures are steadily building in the industry. Once the primary domain of large, vertically integrated utilities providing power at regulated rates, the industry now includes companies selling "un-bundled" power at rates set by competitive markets. These more competitive markets are market based instead of cost based. That brings some very interesting issues regarding recovery of the stranded investments. New generating facilities are being built at costs well below the average costs of some vertically integrated utilities. In this environment, more competition will mean lower rates for wholesale customers.

The intention of Federal Energy Regulation Commission (FERC) is to encourage lower electricity rates by structuring an orderly transition to competitive bulk power markets [2]. Increased competition will result in lower rates. To facilitate this transition, a measured transition from regulated to competitive markets is absolutely essential.

Moving to competitive generation markets will fundamentally change long-standing regulatory relationships. Utilities have invested billions of dollars in order to meet their obligations. Those investments have been made under a "regulatory compact" whereby utilities -- and their shareholders -- expect to recover prudently incurred costs. With the advent of competition, even prudent investments may become stranded.
Reliance on past contractual and regulatory practices must be recognized and past investments must be protected to assure an orderly, fair transition to competition.

The focus of the "Notice of Proposed Rulemaking" (NOPR - Also known as Mega-NOPR due to the magnitude of its impacts) is to facilitate competitive wholesale electric power markets [2]. The key to competitive bulk power markets is opening up transmission services and determining what is the actual value of a "Megawatt". It also includes determining what goes into generating a "Megawatt" and then transmitting it to the customer. At this crossroad for the industry, it is critical to take the regulatory steps now to facilitate the transition to competitive bulk power markets in an orderly manner.

FERC made it clear the importance of determining the costs of ancillary services. These costs need to calculated and recovered from the potential customers of electricity. FERC also made it very clear that since rate-payers will be paying for all these services, it is very important to determine the values of the ancillary services as accurately as possible.

The transmission of electricity from one point to another will include some transmission losses. It will also require some Reactive Power support throughout the transmission path. Such costs need to be built into the tariffs that the transmission company should charge its customers to receive the accurate compensation of its services.

To move to a fair competition it was important for every public utility to price separately all wholesale generation and transmission services (including ancillary services) and take wholesale transmission service under its own tariff. i.e., "functionally un-bundle" its wholesale generation and transmission services. The proposed rule does
not mandate the corporate separation of generation, transmission, and distribution functions. However, it makes it essential for the utility companies to determine each of the costs separately in order to charge its customers for the use of any services [2].

FERC has defined a number of services that can be interpreted as ancillary services. These services will be discussed in detail in later chapters. Since FERC and a number of consultants to the FERC has already completed the task of identifying the ancillary services, the actual methodology to identify these services will be discussed very briefly. However, in order to evaluate the ancillary services properly, it is still important to take a look into the background of the proposal by FERC. The scope of the thesis is research the importance and costs of three of the ancillary services defined by FERC. For this thesis, the three ancillary services chosen include power system security, automatic generation control, and reactive power support. The cost of these three services is most complex to compute due to a large number of variables involved.

This thesis uses a production cost modeling techniques to evaluate each one of the above mentioned ancillary services. The methodology used for evaluation of these ancillary services will be discussed in detail in later chapters. A numerical example of evaluating the costs of ancillary services for an arbitrary power company is also included in this thesis.
CHAPTER 2:

HISTORICAL BACKGROUND OF NOPR

In order to understand the FERC's position in developing the Notice of Proposed Rulemaking, it is important to look into the background of the current electric utility industry and the bulk power markets. This chapter will be concentrating on the historical developments in the electric utility industry that led the FERC to develop the NOPR.

2.1. Structure of the Electric Industry at Enactment of Federal Power Act:

The Federal Power Act was enacted in an age of mostly self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make wholesale requirements sales (bundled sales of generation and transmission) to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered limited service areas. This structure of separate systems arose naturally due primarily to the cost and technological limitations on the distance over which electricity could be transmitted.
Through much of the 1960s, utilities were able to avoid price increases, but still achieve increased profits, because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices. Thus, there was no pressure on regulatory commissions to use regulation to affect the structure of the industry [3].

2.2. Significant Changes in the Electric Industry:

In the late 1960s and throughout the 1970s, a number of significant events occurred in the electric industry that changed the perceptions of utilities and began a shift to a more competitive marketplace for wholesale power. This was the beginning of a period when consumers became concerned about higher electricity rates and questioned any price increases filed by utilities.

During this same time frame, the construction of nuclear and other capital-intensive "baseload" facilities contributed to the continuing cost increases and uncertainties in the industry. These investments were made based on the assumptions that there would be steady increases in the demand for electricity and continued large increases in the price of oil. However, due to conservation and economic downturns, the expected demand increases did not materialize. Load growth virtually disappeared in some areas, and many utilities unexpectedly found themselves with excess capacity. In addition, by the 1980s, the oil cartel collapsed, with a resulting glut of low-priced oil. At the same time, inflation substantially increased the costs of these large "baseload" generating plants. Surging interest rates further increased the cost of the capital needed to
finance and capitalize these projects and completion schedules were significantly extended by, in part, more stringent safety and environmental requirements.

As a result, expensive large baseload plants came onto the market or were in the process of being constructed, for which there was little or no demand. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25% after adjusting for general inflation. Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86% after adjusting for inflation. The rapidly increasing rates for electric power during this period, together with the opportunities provided by the Public Utility Regulatory Policies Act of 1978 (PURPA), also prompted some industrial customers to bypass utilities by constructing their own generation facilities. This further exacerbated rate increases for remaining customers -- primarily residential and commercial customers.

Consumers responded to these "rate shocks" by exerting pressure on regulatory bodies to investigate the prudence of management decisions to build generating plants, especially when construction resulted in cost overruns, excess capacity, or both. Between 1985 and 1992, write-offs of nuclear power plants totaled $22.4 billion. These write-offs significantly reduced the earnings of the affected utilities. Delays in obtaining rate increases to reflect the effects of inflation further reduced investor returns. Thus, many utilities became reluctant to commit capital to long-term construction decisions involving large scale generating plants.
In addition to economic changes in the industry, significant technological changes in both generation and transmission have occurred since 1935. Through the 1960s, bigger was cheaper in the generation sector and the industry was able to capitalize on economies of scale to produce power at lower per-unit costs from larger and larger plants. As a result, large utility companies that could finance and manage construction projects of larger scale had a price advantage over smaller utility companies and customers who might otherwise have considered building their own generating units. Scale economies encouraged power generation by large vertically-integrated utility companies that also transmitted and distributed power. Beginning in the 1970s, however, additional economies of scale in generation were no longer being achieved. A significant factor was that larger generation units were found to need relatively greater maintenance and experience longer downtimes. The electric industry faced the situation "where the price of each incremental unit of electric power exceeded the average cost." Bigger was no longer better [3].

Further dictating against larger generation units were advances in technologies that allowed scale economies to be exploited by smaller size units, thereby allowing smaller new plants to be brought on line at costs below those of the large plants of the 1970s and earlier. Such new technologies include combined cycle units and conventional steam units that use circulating fluidized bed boilers.

The combined cycle generating plants generally use natural gas as their primary fuel. This technology has been made possible by the development of more efficient gas turbines, shorter construction lead times, lower capital costs, increased reliability, and
relatively minimal environmental impacts. Similarly, the circulating fluidized bed combustion boilers, fueled by coal and other conventional fuels, provide a more efficient and less polluting resource.

Today, the optimum size of generation plants has shifted from more than 500 MW (10-year lead time) to smaller units (one-year lead time) in the 50- to 150-MW range. Indeed, smaller and more efficient gas-fired combined-cycle generation facilities can produce power on the grid at a cost between 3 and 5 cents per kWh. This is significantly less than the costs for large plants constructed and installed by utilities over the last decade, which were typically in the range of 4 to 7 cents per kWh for coal plants and 9 to 15 cents for nuclear plants.

2.3. The Public Utility Regulatory Policies Act (PURPA) and the Growth of Competition:

In enacting PURPA, Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates and harming the economy as a whole. To lessen dependence on expensive foreign oil, avoid repetition of the 1977 natural gas shortage, and control consumer costs, Congress sought to encourage electric utilities to conserve oil and natural gas. In particular, Congress sanctioned the development of alternative generation sources designated as "qualifying facilities" (QFs) as a means of reducing the demand for traditional fossil fuels, PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.
PURPA specifically set forth limitations on who, and what, could qualify as QFs. In addition to technological and size criteria, PURPA set limits on who could own QFs. The rapid expansion and performance of the QF industry demonstrated that traditional, vertically integrated public utilities need not be the only sources of reliable power. During this period, the profile of generation investment began to change, and a market for non-traditional power supply beyond the purchases required by PURPA began to emerge. QFs were limited to cogenerators and small power producers. However, other non-traditional power producers who could not meet the QF criteria began to build new capacity to compete in bulk power markets, without such PURPA benefits as the mandatory purchase requirements. These producers, known as independent power producers (IPPs), were predominantly single-asset generation companies that did not own any transmission or distribution facilities. While traditional utilities were generally reluctant at that time to invest in new generating facilities under cost of service regulation, utilities increasingly became interested in participating in this new generation sector. They organized affiliated power producers (APPs), with assets not included in utility rate base, and sought to sell power in their own service territories and the territories of other utilities. At the same time, power marketers arose. These entities -- owning no transmission or generation -- buy and sell power.

There were two major impediments to the development of IPPs and APPs. First, the ownership restrictions of the Public Utility Holding Company Act (PUHCA) severely inhibited these new entities from entering the generation business. Second, these entities needed transmission service in order to compete in electricity markets.
While the FERC had no authority to remove PUHCA restrictions, it encouraged the development of IPPs and APPs, as well as emerging power marketers, by authorizing market-based rates for their power sales on a case-by-case basis and by encouraging more widely available transmission access.

Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs, which entail procedural delays in achieving tariff approvals and changes.

The economic and technological changes in the transmission and generation sectors helped give impetus to the many new entrants in the generating markets who could sell electric energy profitably with smaller scale technology at a lower price than many utilities selling from their existing generation facilities at rates reflecting cost. However, the advantages of these technological advances can be achieved only if more efficient generating plants can obtain access to the regional transmission grids. Because the traditional vertically integrated utilities still favor their own generation if and when they provide transmission access to third parties, barriers continue to exist to cheaper, more efficient generation sources.

2.4. The Energy Policy Act:

In response to the competitive developments following PURPA, and the fact that PUHCA and lack of transmission access remained major barriers to new generators.

2.5. The Present Competitive Environment:

Following the Energy Policy Act, the FERC established rules: (1) for certain generators to obtain EWG status and thus an exemption from PUHCA; and (2) that required transmission information availability. The FERC also pursued a number of initiatives aimed at fostering the development of more competitive bulk power markets, a new look at undue discrimination under the FPA, easing of market entry for sellers of generation from new facilities, and initiation of a number of industry-wide reforms.

In the Stranded Cost NOPR the FERC recognized that the trend toward greater transmission access and the transition to a fully competitive bulk power market could cause some utilities to incur stranded costs as wholesale requirements customers (or retail customers) use their supplier’s transmission to purchase power elsewhere [3]. As the FERC noted, a utility may have built facilities or entered into long-term fuel or purchased power supply contracts with the reasonable expectation that its customers would renew their contracts and would pay their share of long-term investments and other incurred costs. If the customer obtains another power supplier, the utility may have stranded costs. If the utility cannot locate an alternative buyer or somehow mitigate the stranded costs, the FERC explained that “the costs must be recovered from either the departing customer or the remaining customers or borne by the utility's shareholders.” Accordingly, the
FERC proposed to establish provisions concerning the recovery of wholesale and retail stranded costs by public utilities and transmitting utilities [2].

2.6. *Need for Reform:*

The many changes discussed above have converged to create a situation in which new generating capacity can be built and operated at prices substantially lower than many utilities' embedded costs of generation. Non-traditional generators are taking advantage of the opportunity presented by the developments in technology and reduction in fuel costs. Indeed, the non-traditional generators' share of total U.S. electricity generation increased from 4 percent in 1985 to 10 percent in 1993.

Much of this increased share of generation is the result of competitive bidding for new generation resources that has occurred in 37 states. Since 1984, almost 4,000 projects, representing over 400,000 MW, have been offered in response to requests. Over 350 projects have been selected to supply 20,000 MW, and, of these, 126 are now online producing almost 7,800 MW of power. In addition, the cost of utility-generated electricity differs widely across the major regions of the United States. Average utility rates range from 3 to 5 cents in the Northwest to 9 to 11 cents in California [3].

Electricity consumers are demanding access to lower cost supplies available in other regions of the United States, and access to the newer, lower cost generation resources. It is also important that the non-traditional generators of cheaper power be able to gain access to the transmission grid on a non-discriminatory open access basis.
The FERC's goal is to ensure that customers have the benefits of competitively priced generation. However, FERC must do so without abandoning the traditional obligation to ensure that utilities have a fair opportunity to recover prudently incurred costs and that they maintain power supply reliability [2]. As well, the benefits of competition should not come at the expense of other customers. The FERC believes that requiring utilities to provide non-discriminatory open access transmission tariffs, while simultaneously resolving the extremely difficult issue of recovery of transition costs is the key to reconciling these competing demands.

2.7. Market Power:

Unlike new generating capacity, transmission remains and is expected to remain a natural monopoly. The FERC has addressed the natural monopoly character of transmission in the major cases summarized above and in the FERC's recent Transmission Pricing Policy Statement [2]. The monopoly characteristic exists in part because entry into the transmission market is restricted or difficult. In addition, as unit costs are less for larger lines and networks, transmission facilities still exhibit scale economies. From an economic, environmental, and aesthetic viewpoint, it is often better for a single owner (or group of owners) to build a single large transmission line rather than for many transmission owners to build smaller parallel lines on a non-coordinated basis.

Further, effective competition among owners of parallel transmission lines is unlikely, and often impossible, with existing practices and technology. For example, on
an alternating current (AC) electric system, electricity flows on parallel paths based on the impedance of each path. With two electric systems providing parallel contract paths, a share of the actual power flows would occur on each system according to the physical characteristics of the system.

2.8. Discriminatory Access

Some transmission-owning utilities have voluntarily begun to offer unbundled transmission tariff services to third-party suppliers and purchasers of wholesale power, though none have done so to the extent proposed by this rule. However, because utilities are naturally profit maximizers and monopoly suppliers to their native load, the vast majority of transmission-owning utilities have not agreed to give up their market power voluntarily.

Transmission-owning utilities have an incentive to deny access either by not filing any open access tariff or by filing a tariff that offers services inferior to those used by the transmission owner. This is particularly true for those utilities that emerged from the recent decades of technological and legal changes as high-cost generation companies. Open access transmission places their existing generation at risk because their wholesale customers may seek alternative lower price suppliers. It is in their self-interest to maintain and use market power to retain (or expand) market share for their existing generation facilities, at least until they can get their generation costs in line with current market prices. Because generating units are usually depreciated over a 30- to 50-year physical
life, many high cost companies may attempt to exercise transmission market power for decades to preserve the value of past generation investments.

In the past, transmission-owning utilities have discriminated against others seeking transmission access. Transmission-owning utilities have denied access by outright refusals to deal. While such actions tend to be rare, likely because transmission owners fear they may trigger antitrust action, they have occurred. More often, however, discrimination is likely to be manifested more subtly and indirectly. One such way would be for transmission owners to adopt a negotiating strategy that involves a sequence of informational and other requirements over a protracted period of time. By the time all of the requirements are finally satisfied, the window for the customer's trade opportunity has closed. Another way of frustrating access is to substantially change the terms of negotiated agreements through protracted delay, including filings with regulatory agencies.

Another way for transmission-owning utilities to frustrate access and competition is to allow access, but only on non-comparable or unsupportable terms. The conditions put forth to these transmission buyers were inferior to the conditions under which the transmission owners themselves use or could use the transmission grid or on terms and conditions that have no operational or financial basis.

This type of discrimination was also applicable to the ancillary services. A transmitting utility may offer to a transmission customer ancillary services (e.g., scheduling) that are inferior to the services it provides for itself. Transmission owners may be free to choose whether to supply some of these services to themselves or contract
for them if available more cheaply elsewhere. Third-party transmission customers do not always have this option on a comparable basis.

2.9. Analogies to the Natural Gas Industry

The electric industry today is analogous in many ways to the natural gas industry before the FERC issued Order Nos. 436 and 636. Then, natural gas pipelines were primarily merchants offering a bundled sales service, which provided gas to customers at the city-gate from the pipelines’ own system supplies. In addition, pipelines moved a relatively small amount of third-party gas under a separate transportation service. To meet their sales service obligations, pipelines purchased most of their system supply from third-party producers under long-term contracts.

In the early 1980s, due to changing market conditions, the prices under many of these contracts ended up being higher than those available in the then evolving spot market. Because of the long-term contracts and the resulting higher cost gas, system supply gas tended to be more costly than gas that the customers could buy in the competitive spot market. At the same time, the transportation service bundled with a pipeline’s sales service was usually superior to the transportation service third parties could obtain. Essentially, the pipeline would provide itself service that had much greater flexibility and often promised greater reliability than that available to third-party shippers. Pipelines had a considerable incentive to maintain this difference in transportation service quality to make their own, more expensive gas more attractive.
A similar situation exists today in the electric industry. Traditional public utilities deliver bundled service --generation and transmission -- to most of their wholesale customers. They have monopoly control over transmission facilities and thus control access to their customers. The lack of non-discriminatory access to transmission services raises the same general concerns that were prevalent in the gas industry. Accordingly, unless similar regulatory measures are undertaken, the FERC expects the same type of discriminatory and anticompetitive behavior will continue in the electric industry as was present in the gas industry, because denying non-discriminatory access will continue to be in the economic self-interest of transmission monopolists, absent regulatory changes.

The experience in the gas area influences the decision that, at a minimum, functional unbundling of wholesale services is necessary in order to obtain non-discriminatory open access and to avoid anti-competitive behavior in wholesale electricity markets.
ANCILLARY SERVICES

Ancillary services are the services which were traditionally provided by the power utility companies as a part of regular power supply. In the attempt to decrease the cost of power, the utility companies have been forced to identify each of the components of power and evaluate the cost of each one of those components. This is being done so that these ancillary services are provided only to the entities who demand for them and pay for them. In this way, the cost of providing these ancillary services will not be subsidized by the non-users, thus eliminating the free ride effect. This chapter will concentrate on the Ancillary Services, as defined by the FERC and other entities, and the interconnected operations services in some detail. In addition, the scope of interconnected operation services (IOS) will also be discussed in this chapter.

3.1. Defining Ancillary Services:

FERC identified the following six Ancillary Services as necessary to ensure open access [4].

1. Scheduling, System Control and Dispatch
2. Reactive Supply and Voltage Control from Generation Sources
3. Regulation and Frequency Response
4. Energy Imbalance
This thesis will restrict the research to reactive power supply (#2), regulation (#3) and providing operating reserves (#5). The other ancillary services are equally important, but calculation of costs of those ancillary services is rather simple. The ancillary services evaluated in this thesis were selected based on number of variables effecting the costs.

3.2. Interconnected Operations Services:

Ancillary Services are a subset of Interconnected Operations Services (IOS) that FERC requires a Transmission Provider to either provide, offer to provide, or arrange for the provision by others, to Transmission Customers. The IOS Working Group adopted the term IOS for the following services in addition to the ancillary services defined by FERC [3]:

- (Voltage) Regulation
- Backup Supply
- Dynamic Scheduling
- Load Following
- Real Power Transmission Losses
- Power Factor Correction
- Network Stability Services from Generation
- Black Start
The above services are necessary to either ensure system reliability, to ensure open access, or to enable markets while simultaneously maintaining an equitable allocation of costs.

3.3. **New Packaging - Old Services:**

The North American electrical system is sometimes depicted as the largest and most complex "machine" in existence. The power system operates reliably and efficiently due largely to the combined efforts of the entities (Control Areas, generators, etc.) that collectively operate the system.

The services described here (both Ancillary and other IOS) have been around for many years. The services were provided and/or coordinated by the generation and transmission owners (many of whom operated as Control Areas). The services were included or bundled within the integrated generation and transmission service provided by Control Areas to customers.

What is new about the services is the way they are packaged. Instead of being bundled with generation and/or transmission, the individual services are identified. Eventually, many of these services are expected to be separately offered and separately priced by the service providers. In other words the services will be unbundled. The services themselves are not new, only the packaging [3] [6].

3.4. **Need for the Evaluation:**

The restructuring of the power industry is partially driven by federal legislation and the regulatory actions of FERC and the state utility commissions, partially by
economic factors, and partially by the independent actions of the players in the electric
market. To ensure the maintenance of system reliability, the operational and technical
aspects of the IOS required to maintain reliability while facilitating open access and
enabling power markets, became the focus of all research into the NOPR. Operational
and related issues that were addressed included [3]:

- What are the obligations of the suppliers of the services?
- What are the obligations of the purchasers of the services?
- What are the roles of the Control Areas and other key players?
- What are the technical requirements of the services?
- Who will administer the purchase and provision of the services?
- Who will be the providers of last resort of the services?
- Can the services be self-provided by Transmission Customers?
CHAPTER 4:

THE NORTH AMERICAN SYSTEM

The North American power system has evolved over the past 100 years. Initially, independent companies built and operated isolated (no electrical interconnections between companies) power systems. These isolated power systems were dependent on their own resources to handle both normal and emergency events. Beginning in the 1930's utilities began to interconnect with one another. The driving forces behind the electrical interconnections were the ability to share resources, to schedule interchange, and in general increase reliability while lowering operating costs [3].

![Figure 1: The Interconnections of North America](image)

This chapter also discusses the various interconnections in the North American system. This division of the system can be observed in the figure 1. There are certain
aspects of the system that only pertain to one of the interconnections. In this thesis, the research is limited to criteria set forth by Western System Coordinating Council.

From these early inter-connections evolved today's complex power system designs. North America is currently divided into four major Interconnections as illustrated in Figure 1. (Alaska and Hawaii contain separate, smaller Inter-connections.) The different Interconnections do not connect with one another via ac transmission lines. Thus, interchange transactions between the respective Inter-connections are limited to the capacity of available dc (direct current) tie-lines.

4.1. The Control Area Concept:

For each of the Interconnections to operate safely, reliably, and provide dependable electric service to its customers, it must be continuously monitored and controlled. This monitoring and control function is distributed among the Control Areas that comprise the Interconnections. There are approximately 150 Control Areas in the four major North American Interconnections.

CONTROL AREA DEFINITION:

A Control Area is an electrical system bounded by tie-line metering and telemetry. A Control Area controls generation directly to maintain interchange schedules with other Control Areas and contributes to frequency regulation of the Interconnection in which it is physically located [8]. A Control Area is an electric system that meets the following two requirements:
• Directly controls its generation to continuously balance its actual interchange and scheduled interchange, and...

• Assists the entire Interconnection with regulating and stabilizing the Interconnection's frequency.

**CONTROL AREA RECOGNITION:**

To be recognized as a Control Area, a power system must be reviewed and confirmed by national and regional reliability organization representatives (see the NERC description that follows) that the system meets the following basic requirements [9]:

• Has metered interconnections (tie-lines) with other Control Areas and the necessary contracts to use those connections.

• Has the ability to effectively control generation and match its net actual interchange to its net scheduled interchange pursuant to NERC Control Performance Standards.

• Has generators equipped with governors under its control that are able to respond properly to Interconnection frequency changes.

• Has a control center with 24-hour-per-day staffing.

**4.2. NERC and the Regional Councils:**

The operation and control of electrical power systems in North America has evolved into its present structure over the past century as power systems have grown in size and complexity. The present operational structure of power systems is largely defined and controlled by participation of all involved parties in an organization called
NERC (North American Electric Reliability Council). NERC in turn is composed of ten regional reliability councils.

NERC was formed shortly after the 1965 Northeast Blackout. This event clearly demonstrated the interdependence in the operations of all parties participating in an interconnected power system. The need for all these parties to use consistent planning and operating procedures was clear, and NERC was the vehicle chosen to implement that consistency [11].

NERC's primary objective is to promote the reliability of the electricity supply by creating and monitoring compliance with NERC policies, principles, criteria, standards and guides for reliability. The collection of NERC operating documents, termed the "rules of the road", sets forth requirements and guidelines for operating and planning electric generating capacity and interconnected power systems.

4.3. **IOS Selection Criteria:**

General and specific selection criteria for determining if an enabling market function is an IOS were developed and used to create a list of required IOS. Note that this list of required IOS is just an initial attempt at defining IOS. As time passes and operating experience in the emerging market structure accumulates, it is likely that additions, deletions and modifications will change the list contents.

**General Criteria for Identifying IOS:**

IOS were not arbitrarily selected from available enabling functions, but derived from specific needs for power system reliability, for power system operability. to ensure
cost equity, and to support open access. Three general selection criteria for determining if an enabling function is a required IOS are described below [3].

**Criteria 1: Reliability**

If an enabling function is required to ensure the reliable operation of the interconnected power system, it satisfies general Criteria 1. For example, following a generation loss Operating Reserves (Spinning and Supplemental) are often necessary to ensure an ability to balance load and generation and recover the system frequency.

**Criteria 2: Open Access and Enable Markets**

If an enabling function is required to ensure that Transmission Customers are provided open and equal access and that market structures are enabled, it satisfies general Criteria 2. IOS are made available to Transmission Customers to enable all customers to compete on an equal footing with established market players. For example, if a Dynamic Scheduling IOS were not available, a Load Serving Entity’s choices in obtaining certain services could be restricted to its Host Control Area.

**Criteria 3: Equity**

An enabling function must, in general, satisfy either Criteria 1 or 2 to be designated a required IOS. In contrast, general selection Criteria 3 is an all encompassing criteria that applies to the selection of all IOS. All of the entities that make use of the transmission system must equitably share the costs associated with the use of that system. If users are allowed access to the transmission system without a proportional share of the costs, unfair market conditions exist. For example, a Real Power Transmission Losses
IOS is necessary as it is designed to ensure that all those who create real power losses reimburse the power system for those losses.

Figure 2 graphically illustrates the application of the three general selection criteria. Note that the equity criteria applies to all services while Criteria 1 and 2 apply to selected services. If these criteria are applied to FERC's Ancillary Services it is apparent that all three criteria apply to each of the six Ancillary Services. (All six of FERC's Ancillary Services would be situated at the intersection of the two circles in Figure 2.)

![Figure 2: General Selection Criteria for Determining If an Enabling Function is an IOS](image)

**Figure 2** General Selection Criteria for Determining If an Enabling Function is an IOS [3]
4.4. **Role of the Control Areas:**

New players will emerge as the electricity market evolves and matures. Transmission Providers, Transmission Customers, Generation Providers, Power Marketers, Load Serving Entities, etc. are some of the possible market players. (The players and their functions are described in a later section.)

Control Areas are a necessary entity. The Control Area is the glue that holds the interconnected power system together. Control Areas continually monitor the health of their portion of the power system and ensure all players are provided equal access to the transmission system. Control Areas currently typically perform the functions of generation/load balance, transmission system security, and emergency preparedness. It is assumed that regardless of the new market structure the Control Areas will continue to perform the generation/load balance function.

IOS often provide a shared benefit. For example, consider Operating Reserves. It is generally more cost effective to share reserve requirements than to self-supply. The Control Area operator serves the critical function of enabling this sharing to occur.

Some IOS by their nature must be provided through a Control Area. The Control Area will often serve as the intermediary between IOS suppliers and IOS customers to schedule, coordinate, measure, verify, etc. Figure 3 illustrates the key role of the Control Areas. For IOS that may not necessarily be required to come directly from the Control Area, the Control Area will typically serve a role of coordinating, scheduling, verification, accounting, payback, etc.
There are several critical duties, which in the opinion of the IOS WG must be performed by Control Areas.

**Primary Duties:**

All of the Control Areas in an Interconnection have two primary duties; to maintain a close match between their actual and scheduled interchange and contribute to the frequency regulation of the Interconnection. These primary duties are fundamental to sound system operation and must be continued. A Control Area controls its actual interchange and contributes to frequency regulation by adjusting its controlled generation through an automatic generation control system, or AGC. NERC and the Regional Councils have developed methods and procedures for monitoring the effectiveness of AGC systems. This monitoring role must continue.
Reserve Monitoring:

Control Areas have always been responsible for maintaining adequate reserve levels. As more players enter the electrical marketplace the task of monitoring reserve levels will likely increase in complexity. Control Areas are ideally suited as the reserve monitoring entity.

Scheduling:

Control Areas are the agent for monitoring, administering and coordinating all scheduling activities. A Purchasing-Selling Entity must work through their Control Area when scheduling. A central scheduling role is critical to ensure system reliability, open and fair access and productive use of transmission and generation resources.

IOS:

The Control Areas should be the designated monitor for compliance by IOS purchasers and the qualifier of IOS suppliers. As a condition of service within a Control Area’s system, all Transmission Customers must satisfy IOS purchase requirements and all IOS suppliers must satisfy the standards of IOS suppliers.

Compliance With Operating Policies:

A Control Area is obligated to adhere to all NERC Operating Criteria, Requirements, and Standards. Regional Councils, Power Pools, or other associations also may impose their own operating criteria and procedures. It is recommended that all NERC and Regional Operating guidelines be updated to reflect the new operating
environment in general and IOS in particular. IOS definitions should become part of each Regions Operating Policies.

**Compliance with Control Performance Standards:**

NERC and the Regional Councils have developed generation control performance standards to evaluate a Control Area's performance in maintaining a load to generation balance. Two sets of standards are used, one for normal conditions (the A1 and A2 standards) and one for disturbance conditions (the B1 and B2 standards). Methods have been developed to calculate a Control Area's conformance to these standards. Control Areas are then able to judge their own performance and compare their performance to the performance of other Control Areas. These standards may have to be modified and new standards developed to adjust for emerging markets. In addition, sets of standards may be required for various IOS.

**4.5. Functions in the Electric Power Market:**

The functions performed in an electric power market can be described in terms of seven functional areas. In the past, all of these functions may have been performed by one vertically integrated utility. In future markets different entities may perform the various functions. The functional areas include Generation, Transmission Wires, Distribution Wires, Wholesale Sales, Retail Sales, Market Administration, and System Operations.
**Generation:**

Generation provides capacity and energy to the system. Generation providers include independent power producers (IPP), qualifying facilities (QF), and the generating assets of vertically integrated utilities.

**Transmission Wires:**

Transmission Wires provides for the transmission of power and energy from generation sources to the various transmission substations. Transmission Wires includes transmission companies and the transmission assets of vertically integrated utilities.

**Distribution Wires:**

Distribution Wires provides for the distribution of power and energy from the local transmission substation to the end-use customers. Distribution Wires includes distribution companies and the distribution assets of vertically integrated utilities and transmission dependent utilities (municipal utilities, Cooperatives, etc.).

**Wholesale Sales:**

Wholesale Sales provides for the wholesale sale of capacity and energy services. Wholesale Sales involves sales from a generator to an entity which then sells to either another entity or an end-use customer. Wholesale Sales includes Generators, Power Marketers, and the power marketing branches of vertically integrated utilities.
**Retail Sales:**

Retail Sales provides for the retail sale of capacity and energy to an end-use customer. Retail Sales includes distribution utilities, retail aggregators and Load Serving Entities (LSE).

**Market Administration:**

Market Administration provides for the complete or partial operation of the central market structure. The Market Administration function is performed by Power Exchanges and Power Pools.

**System Operations:**

System Operations provides for the coordination, operation and control of the power system. System Operations includes Independent System Operators (ISO), Control Areas, tight power pools, sub-Control Areas and Scheduling Coordinators.

**4.6. Market Entities for IOS:**

The functional areas described in Section 4.4 may be performed by several different entities that exist in the electrical market. The following is a list and description of entities. This list is not complete as new entities may emerge at any time especially given the uncertainty surrounding the future electric marketplace [3].

**Control Areas:**

Control Areas are entities which operate an automatic generation control (AGC) system and provide real-time monitoring and dispatch of generation and transmission.
Two types of Control Areas are described below and illustrated in Figure 5, the Host Control Area and the metered or electronic Control Area.

**Host Control Areas:**

The Host Control Area is the Control Area in which the transmission system that a Load Serving Entity (LSE) is connected to is physically located. In the absence of dynamic scheduling (see Figure 4), the Host Control Area is the LSE's generation Control Area. If the transmission system to which the LSE is connected is physically located within several Control Areas, those Control Areas are the Host Control Areas for portions of the LSE's load. The Host Control Area of an LSE never changes except if the LSE forms its own Control Area.

**Control Area:**

The LSE's Control Area is the Control Area that performs the generation control function (AGC) for the LSE. This Control Area could also be referred to as the LSE's metered Control Area or electronic Control Area. Using dynamic scheduling, an LSE may change its Control Area from its Host Control Area to a new Control. The new Control Area then becomes the LSE's generation Control Area.
**FIGURE 4 CONTROL AREA CONCEPT [3]**

**PURCHASING-SELLING ENTITIES (PSE):**

Purchasing-Selling Entities (PSEs) are non-Control Area systems that fall into two categories:

1. Those that operate generation or serve customers directly, and
2. Those that perform marketing functions only and do not operate generation or serve customers directly.
PSEs that neither operate generation nor serve customers directly, such as Power Marketers, are not within the metered boundaries of a Control Area. This type of entity is not associated with a Host Control Area per se, but must still rely on Control Areas for interchange schedule confirmation and implementation as well as the provision for certain IOS.

Purchasing-Selling Entities must be able to demonstrate to their respective Control Areas that all required IOS have been obtained. Types of PSE include Generation Providers, Load Serving Entities (LSE's) and Power Marketers.

**Generation Provider:**

An entity that provides capacity and energy to the power system. A Generation Provider does not necessarily generate the power and energy they deliver to their customers.

**Load Serving Entity (LSE):**

An entity which either aggregates load (wholesale) or directly serves load (retail).

**Power Marketer:**

An entity that performs a power marketing function (buying and selling) and does not operate generation or serve customers directly. A Power Marketer takes title to energy and capacity and markets the product to wholesale and retail customers.

**Transmission Providers:**

Transmission Providers are, in the strictest sense, just that - entities that are responsible for providing transmission service to Transmission Customers. In the
practical sense, most Transmission Providers also operate generation, and many are Control Areas.

A Transmission Provider does not simply provide transmission service but is obligated to provide reliable (within contract limitations) transmission service. The reliability role of the Transmission Provider extends to IOS. The Transmission Provider is the provider of last resort for several IOS. As such, the Transmission Provider provides or arranges for the provision of the required IOS if an obligated entity does not do so in a timely fashion. The provider of last resort role is a critical power system reliability function.

Transmission Providers may be a vertically integrated utility, a transmission company, an ISO, a Power Pool or other entity which has the ability to provide transmission service.

**TRANSMISSION CUSTOMERS:**

A Transmission Customer is an entity which purchases transmission service from a Transmission Provider. Transmission Customers may be PSEs, Control Areas, or the Transmission Provider itself. The definition for a Transmission Customer is so broad that it helps to think of three distinct types of Transmission Customer:

- Those who simply connect to the transmission system
  - For example, a generator providing reserves
- Those who wheel across the transmission system
  - For example, a Power Marketer
- Those who directly serve load or are aggregators of load.
For example, an LSE

**IOS Supplier:**

It could be possible that an entity may be a supplier of IOS and not fit into any of the other categories described in this section. The market structure of IOS suppliers is not yet developed and the possible suppliers unknown at this time.

**4.7. Existing Market Structures:**

The existing electricity market within every North American Interconnection is dominated by vertically integrated utilities. The utilities typically integrate all seven functional areas, absorbing the roles of all entities within their corporate structure.

For example, Figure 5 illustrates how players and functions could interact in the dominant form of the existing market structure. (For simplicity only one utility and one neighboring Control Area is shown in Figure 5.) The utility represented owns, operates, and control its own generation, transmission and distribution systems. The utility performs wholesale sales to other Control Areas and retail sales to its own customers.

The utility is also a Control Area and performs its own system operations function. Market Administration is accomplished in cooperation with other Control Areas and, if it exists, a Power Pool. The utility in Figure 5 has a corporate structure which integrates the roles of all necessary entities. This utility functions as a Control Area. Transmission Provider, Transmission Customer, Load Serving Entity, Power Marketer and Generation Provider.
The Control Area is responsible for scheduling transactions, generation dispatch, transmission system reliability, and various other system control tasks. All of the services required to operate an interconnected power system are either provided for or arranged by the Control Areas. Wholesale sales are constantly being made between Control Areas to minimize operating costs and maximize profitability while maintaining system reliability.

**Figure 5 Dominant form of the existing market structure [3]**

**Role of Power Pools:**

Utilities and Control Areas may band together to form a Power Pool. A Power Pool may be a "loose" or "tight" pool. A loose Power Pool is typically formed to ensure
system reliability and/or to share resources (reserves). An example of a loose Power Pool is the Mid-continent Area Power Pool (MAPP). The members of MAPP have entered into reserve sharing agreements and follow joint operating practices but the generation control function is handled by the individual Control Areas that are members of MAPP [3].

A tight Power Pool is the equivalent of a large Control Area in which the generation control of multiple utilities (many of which are capable of being their own Control Area) is turned over to the Power Pool’s control center. For example, Pennsylvania, Jersey, Maryland (PJM) is a tight Power Pool in which the generation control function is handled by PJM system operations. This method of system operation is designed to reduce the operating costs for all the utilities of PJM as all generation is part of a common pot and the least cost units receive preference.

4.8. The Transition Phase:

The current electrical marketplace is in a transition phase. New entities have emerged in recent years and as time progresses these entities will play an increasingly important role. Figure 6 illustrates some of the recent changes to the electrical market. The functions of newer entities such as IPPs (Generation), Power Marketers (Wholesale Sales), and LSEs (Retail Sales) are illustrated. The new entities arrange with their Control Area’s to perform their function. For example, the Power Marketer and IPP schedule through their respective Control Areas.
The Control Area is still a critical link that performs a key coordination role and generation/load balance role thereby helping ensure system reliability. The IOS WG envisions that the Control Areas' role will continue in any emerging market structure.

4.9. IOS Market Structure:

It is envisioned that market structures for IOS will gradually develop that include IOS purchasers and IOS suppliers. The purchaser end of the IOS market will include all those Transmission Customers who are required to obtain IOS. The supplier end of the IOS market will include all those entities who choose (and are qualified) to supply the actual IOS or supply the resources required to create an IOS.

![Figure 6: The Transitional Market Structure](image-url)

**Figure 6 The Transitional Market Structure [3]**

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Figure 7 illustrates a possible market structure for the Community Service classification of IOS.

A typical transaction in this IOS market structure would entail a Transmission Customer purchasing an IOS from their Transmission Provider. The Transmission Provider arranges for the provision of this IOS with the responsible Control Area. The Transmission Provider purchases the resources to create the IOS from available, qualified IOS Suppliers. (For example, the Transmission Provider could purchase spinning reserves from a generation source.) The IOS Supplier supplies the IOS capabilities to the Control Area. The Control Area creates the IOS (for example, the Control Area could...
create Operating Reserve - Spinning from spinning reserves) and then deploys the service to the Transmission Customer.

The Control Area is the entity that actually deploys community IOS to the Transmission Customer. In many IOS transactions, the Transmission Provider can be viewed of as the contractual provider of the IOS while the Control Area is the physical provider of the IOS.

4.10. Self Provision of IOS:

A Transmission Customer may also choose to self-provide a community IOS. The Transmission Customer may use their own resources to self-provide or obtain the necessary resources directly from the IOS supplier. In either scenario for self-provision, the Control Area receives the IOS capabilities, creates the IOS, and deploys the service to the Transmission Customer.
CHAPTER 5:

APPROACH TO CALCULATING COSTS

This chapter discussed the approach that was used in this thesis to calculate the cost of the three ancillary services. In order to accurately calculate the value of a "megawatt", it is important to understand some basics of the power generation. This chapter also discusses some of the most commonly used terms in the power generation industry.

5.1. Factors Determining Generator Operation:

In the Power Industry, various types of generation units are used for different purposes. The operation of a particular generator is defined based on factors including nature of the unit, type of fuel it uses, its ramp rate, its minimum up-time and down-time, startup time, emissions, safety factors, and cycling costs.

NATURE OF THE UNIT:

Due to significant difference in the behavior of nuclear, coal fired, gas fired and hydroelectric units, the units are used for different purposes. For instance, in nuclear powered units, it is not possible to change the amount of fuel rods (Highly radioactive) to control the output of the unit. A very little control can be achieved by controlling the heat generated. Therefore such units have very little difference between minimum and maximum generating capacities.
Coal and gas fired units provide more control over the amount of fuel input into the unit, thus controlling the output of the unit. The coal can be controlled in the coal pile, or by slowing down the conveyor belt (Commonly used to transport coal from the coal pile to the burners). The gas flow in the gas fired units can be controlled by controlling the gas valves on the gas line.

Hydroelectric power units are easier to control, since the primary control rests with controlling the flow of water through the turbines. All these factors make the unit feasible for certain type of loads and not so feasible for other types of load. In areas where there is a huge difference in the day (on-peak) and night (off-peak) loads, nuclear powered units are not attractive due to inability to swing the unit’s output easily. Other factors as the initial investment versus return criteria is used to develop schemes to build new generation resources.

**Type of Fuel Used:**

Type of fuel used can determine the availability and storage capacity of the fuel. For example, unused coal can be stored in the coal piles, as long as new shipment of coal does not arrive. However, it is not that easy to store the gas once it is already flowing in the pipelines. Some companies do hold gas storage facilities, but it costs a lot for other companies to store gas in rented gas storage. The unused nuclear fuel rods can easily be stored, but safety is a major concern while replacing the fuel rods.

For these reasons, the gas for the units is requested based on pre-analysis of the system, given the available resources and the load forecast. Once the gas is purchased by the power generation facility from the gas vendor, it is important to use the ordered gas.
If for some reason the gas cannot be used (due to load forecasting errors or sudden changes in the area temperatures), arrangements have to be made with the gas vendor, or some other storage company to save the gas for later use.

**Ramp Rate:**

Ramp rate is the speed of the unit response to control signals. Coal units generally have ramp rate around 2 MW / Minute. Most Gas Units have ramp rates higher than Coal Units. During the periods of high load volatility, it is important to provide the system with enough load following capability. In some cases there might be four or five units needed at one time to provide enough load following capability for the system.

The ramp-rate provides information on how quickly a unit can respond to load changes, or emergencies. Higher ramp rates give the power system dispatchers more ease to operate the system in the most economical way. The ramp rates also play a vital role in calculation of on-line spinning reserve calculation. A unit with a ramp rate of 2 MW / minute can only contribute 20 MW to the on-line spinning reserves, even if it is backed down more than that. This is due to the fact that the spinning reserves have to be made available to the system within 10 minute period. Therefore it is common practice to load the units with lower ramp-rates to the maximum and back the high ramp-rate units to provide on-line spinning reserves.

**Minimum Up Time and Down Time:**

Minimum up time is the time a unit has to stay on-line after it comes on-line. The up time is set based on safety, reliability and cost of start-up fuels and labor. Minimum
down time is the time the unit has to stay off-line when it comes off-line. This time is based on the cool-down time of the unit. Under some special conditions, these times can also be based on emissions from a particular unit. In case of nuclear units, minimum down time and up time is also controlled by supervisory boards.

These factors play an important role when committing the units for generation. A coal unit cannot be put on-line just for the peak of the day, due to its larger up-time. If the unit is committed for the peak load of the day, the unit will have to stay an additional number of hours to meet its minimum up-time (Generally 8-12 hours for coal fired units). In such cases, gas powered generation provides more flexibility in operation.

**START TIME:**

The Start Time is the time it takes a unit to get on-line and upto full load from a cold start. The start time of less than 10 minutes makes the unit available for off-line quick-start reserves. Such units are designated as *peakers* or peaking units. Such units are dispatched differently than the regular thermal units.

High start-up times, as in case of nuclear and coal units, makes it impossible to use these units in case of trip of another unit or transmission. NERC allows the use of quick-start units (On-line and upto full load within 10 minutes) to contribute towards off-line operating reserves [8].

**EMISSIONS:**

Certain states require certain emission standards for the units located in specific locations. Such standards also limit the operation of some units at any one time using a
specific fuel. Emissions can also be monitored by the plant. In these cases only a certain number of units out of all available units can be used on-line at one time to keep the plant emissions under the specified.

**SAFETY:**

Safety of the workers and the equipment can also lead to some restrictions on certain units. For instance while re-fueling a Nuclear Unit, extreme pre-cautions are taken to avoid any leak of radioactive material into the atmosphere. All thermal units have to be cooled down to a safe temperature, before any work can be performed close to the boiler.

**CYCLING COSTS:**

Cycling costs of the unit also play an important role in decision to take a unit off-line or put a unit on-line. These are the mechanical wear and tear cost that are incurred when a unit is cycled. These costs will be discussed in detail in a later section.

**5.2. Restrictions on Hydroelectric Units:**

Hydroelectric power plants also have certain restrictions associated with their operation. Even though the amount of water passing through the turbines can be controlled by the operations personnel, but there is a set amount of water that has to be passed every period. These limits are set generally by Bureau of Land Management (BLM) and other state agencies.

In certain areas, the water from the hydroelectric power plants is used for agriculture down the stream. In that case, to protect the interest of communities down the
stream. A certain minimum amount of water has to be passed every day. There are also some ecological controlling facts for water. During a certain season, fish flush (Migrating of fish up the river) also controls the maximum water that can be passed every day. This controls the water up the river (or lake) giving fish enough water to complete the migration upwards. Other water controlling factors include snow pack, amount of seasonal rain fall, avoidance of floods down the river etc.

5.3. Unit Categories:

Based on the above mentioned factors, the units can be categorized into different classifications including base loaded units, cycled units, peaking units, quick-start units, and hydroelectric units.

**Base Loaded Units:**

These are the units on which the load stays constant most of the time. These have very high costs of automatic generation control due to high cycling costs. These units are also dispatched for long terms and are not taken off-line during the off-peak hours. Nuclear units are a prime example of such units. Load does not vary much on the nuclear units and the units are generally not taken off-line for load reasons. Larger coal units are also considered base loaded units.

Gas units in combined cycle mode are also considered semi base loaded units. In combined cycle units, one or two gas units operate in normal operation mode. A Heat Recovery Steam Generator (HRSG) recovers the heat from the boilers of the gas units and puts it through a steam turbine. The steam turbine uses just the high pressured steam.
from the already operating gas units, thus does not bear a fuel cost. In combined cycle mode, the units are priced as a combined cycle unit, not as separate units. The gas units have to be on-line for a specific period of time (approximately 4 hours or more) to generate enough steam to put the heat recovery steam generator on-line. Due to such lag time, these units are considered base loaded units under most circumstances.

**Cycled Units:**

These are the units which are brought on-line for load whenever needed. Some of these units come on-line weekly to serve the business and industrial loads during the weekdays. These are then taken off-line for the weekends when the industrial and business loads are minimal. These units are mainly gas fired units. Minimum on-line time for these units average around 8 hours. Down time is average 4 hours (Minimum). Such specifications make these units flexible to load changes and outages.

These units can also be brought on-line during severe weather conditions. On the other hand these units some time replace the base loaded units during minor outages and trips.

**Peaking Units:**

These units are used for peak shaving purposes. These units come on-line during sudden increases in the load, when the ramp rates of the on-line units is not enough to cover the changes in load. These units generally cover for early morning business load increases as well as evening (lighting) load increases. During extreme summer heat, these units are also used for peak air conditioning load.
Due to the special purpose of these units, the maximum and minimum capacities on these units are very close. Their start-time, up-time and down-time are also significantly lower than other units making these units very flexible.

**Quick-start Units:**

These units are the units which can be made available for full load and synchronized to the system, from cold start, in less than 10 minutes (Western System Coordinating Council power system operating guidelines). This unique feature makes these units part of the off-line quick-start reserve (Part of overall operating reserve).

**Hydroelectric Units:**

Hydroelectric units are unique in the way that these units provide means to transfer energy from one part of the period to the other part of the period. The amount of water to be passed through the hydroelectric power plants is pre-determined. Generally the period consists of a day. It is up to the power company to allocate the hydroelectric resources to the most beneficial part of the day. During off-peak hours, the units are kept to minimum output to conserve maximum water. The water is then passed through at the maximum rate during the peak hours to replace the most expensive power.

These units also have very good load following (Automatic generation control) capabilities. These units can be moved hundreds of megawatts within minutes by simple opening up the water flow through valves.

Due to no fuel costs, these units are also relatively cheaper than any other type of power.
5.4. **Fixed Vs. Variable Costs:**

In order to study the cost of providing ancillary services, it is important to understand the difference between fixed and variable costs. This difference becomes vital when trying to generate profits to recover stranded investments. Variable costs are important in determining the cost of *operation* of a particular unit or generation facility. The generation facilities with least amount of stranded investments and with least operating costs are bound to be successful in a market based competitive environment.

**Fixed Costs:**

These are the costs of ownership of the generation station. These costs also include the costs of the unit, buildings, initial investment, fixed labor, and shareholder equity. In a competitive environment the fixed costs are stranded costs. Recovery of the stranded assets is based on the competitiveness of the electricity market.

The price of the ancillary services and the primary product (Electric Energy) is based on the variable costs. The profits, if any from providing the services are later used to recover some of the stranded investments. The variable costs per unit of power can be minimized by the optimal and efficient use of generation resources.

There are certain types of costs which can be considered partially fixed and partially variable. One such example is the cost of labor. If the generation plant is manned during the non-operating periods i.e. the labor is paid to be at the plant during that period, it will be considered fixed (sunk) cost and will not be included in the calculation of operating cost of the unit. However, if the labor is hired for the operation...
of the plant, then it will be considered as a part of the operating cost calculation of the unit.

In the competitive market, when companies are trying to minimize their operating costs to make their generation more productive, special attention needs to be paid to the recovery of the fixed costs (Stranded assets). These were the costs that the initial investors and the share holders paid for the particular generation plant.

**Variable Costs:**

These are the costs of providing the products. These costs include the costs of fuel, and wear and tear on the unit due to operation. The more the unit is operated, the higher these variable costs are.

When calculating the variable cost of operating a unit, careful attention needs to be paid to the actual costs. Any non-variable (fixed) costs, if included, will make the unit more expensive for dispatch and commitment purposes. Thus the unit will lose some opportunities for operation. On the other hand, if some variable costs are not included in the operating costs, operation of the unit might end up costing to the generation company.

**5.5. System Security:**

Every electric utility company, small or large, is required by NERC to maintain a high level of security of the system. The security of individual system, in turn, results in the security of the interconnected system. Still there might be cases where a single company can initiate or contribute to the collapse of the entire interconnected system.
The importance of system security became evident by the Northeast Blackout of 1965 when on November 9, 1965, the electric utility industry experienced the biggest power failure in the history [11]. While major power outages did take place before and after this event, no single event ever came close to what was later called Great Northeast Blackout of 1965. As it turned out, some 30 million people lost power with minutes and the normal life came to a halt in the communities. Many millions of peoples stayed without power for as long as 13 hours.

**Responsibility of Maintaining System Security:**

Bulk power dispatchers are responsible for maintenance of security of the system. The primary responsibility of the bulk power dispatcher is to make sure that the system is operating in *stable* manner. Stability of power system is defined as equality of mechanical input from the generation units to the electrical output produced by the system.

Generally the factors affecting system stability can be divided into two groups.

1. Faults - line to line, line to line to line, 3 phase etc.
2. Loss of generation (Due to mechanical or electrical system failure).

A system is considered secure if it is able to withstand contingencies. The contingencies could be loss of a generation unit or loss of transmission failure. Reserves can be kept based on two different factors.

a. Reserves based on percentage of the system load.

b. Reserves based on the single largest contingency.
Both of the above methods are very commonly used in the electric power industry. Aside from the primary responsibility of maintaining system security, the Bulk Power Dispatchers are also responsible for economic dispatch of the system. Economic dispatch is defined as the most economical way to operate the system under the given conditions. There are five most commonly used states of system security [1],

**Normal State:**

In normal operating mode, the loads are met by the combination of generation and purchase power resources. Also all of the equipment (Generators, Transmission Lines) operate within the normal operating ratings.

**Alert State:**

Alert state is the state of the system when a single loss of generator or transmission could result in the system emergency state.

**Emergency State:**

In an emergency state, the system is no longer secure. Load is served but some of the equipment is being over stressed i.e. operated outside the normal ratings of the equipment.

**In Extremis State:**

In this state the system is not secure and also.

- Load is not being served.
- System is splitting / synchronous operation may be lost.
- Frequency is off normal.
**Restorative State:**

In this state, the system is being re-synchronized which would eventually result in the operation of system in normal mode.

**Costing Reserves:**

In the light of recent deregulation of the electric industry and consequential increase in the competition, electric utilities have realized that it might be much more economical to operate in a manner to optimize the whole system instead of optimizing individual control areas. For example, a company in Southern California might not be able to generate cheaper in summer (Peak loading time for Southern California), and it might be beneficial to purchase reserves and power from the utilities in the northwest (Winter peaking utilities). Then by the same token, the utilities in northwest can purchase from southern California utilities during winter, when the load on southern California system is relatively mild. For any of such transaction to be beneficial to the supplier and to the buyer, proper analysis of the power system must be done to evaluate the cost of reserves.

**5.6. Automatic generation control:**

Automatic Generation Control (AGC) is the capability of the unit to automatically respond to the changes in the load. Generally one or more units in a system are set in this mode so that the under-generation (low frequency) or over-generation (high frequency) conditions do not take place. The base loaded units are usually not put in this mode due to high cycling costs of those units.
A properly tuned AGC system is needed for stable, reliable system operation, match system generation to obligations (load and sales), control flow on the tie lines, maintain stable system frequency, maintain NERC criteria (A1 and A2 Criteria - discussed later), optimize system economy, implement economic dispatch, and to implement off-system sales contracts [1].

**Types of Control:**

Automatic Generation Control generally consists of two types of control.

**Economic Dispatch Calculation:**

Economic Dispatch Calculation is done every five minutes on most of the systems. This process calculates each of the synchronized units' incremental cost. It then dispatches the units based on equal incremental costs. The results from this calculation are also transferred to load frequency control [1].

**Load Frequency Control:**

This used to be historically performed on analog computers. Implementation on newer digital computers is now in progress. This sends signals to individual plants to raise or lower the load on the unit based on the system load [1].

**Area Control Error (ACE):**

ACE or Area Control Error can be given by the following equation,

\[ ACE = I_a - I_s + F_{bus} \times (F_s - F_a) \]  

where,

\[ I_a = \text{Actual Interchange Flow} \]
I, = Scheduled Interchange Flow

\[ F_{\text{bias}} = \text{Frequency Support Bias} = 291 \text{ MW} / 0.1 \text{ Hz.} \]

\[ F_A = \text{Actual System Frequency} \]

\[ F_S = \text{Scheduled System Frequency} \]

Interchange stands for the net interchange on the tie lines. The frequency bias support is the individual company's support to the interconnection frequency.

Scheduled frequency is typically 60 HZ. But it could be 59.98 Hz. Or 60.02 Hz. If time correction is in effect. Time correction is NERC guide to prevent the integrated frequency error (Time error of a standard electric clock) on the interconnection from varying by more than +/- 8 seconds [1].

Automatic Generation Control always tends to drive the ACE toward zero. High frequency causes ACE to go positive i.e. too much generation on the system. On the other hand, negative ACE means less generation than obligations and too much power is flowing into the system.

**NERC Guidelines:**

National Electricity Reliability Council or NERC has established criteria for load following and automatic generation control. It is important to note that these are mere recommendations that NERC makes to the power utility companies and control areas. Adhering to these recommendations is not enforced and is completely up to the power utility company. However in case of power failures, FERC can ask the utility companies to provide proof that it was following NERC recommendations when the power failure happened.
**A1 Criteria:**

The NERC guide that most directly impact AGC operation include the A1 and A2 criteria. A1 requires that the system Area Control Error (ACE) cross zero within each sliding ten minute window i.e. the ACE should cross zero within ten minutes of last zero crossing at least ninety percent of the time. This insures that no utility constantly rides the ties (Takes energy from the interconnected grid without scheduling or paying for it [8].

**A2 Criteria:**

The A2 criteria requires that the amount of inadvertent energy that accumulates in any discrete ten minute period be less than an amount proportional to the highest ten minute change in the load from the previous year. at least ninety percent of the time [8].

**THE COST OF AUTOMATIC GENERATION CONTROL:**

The cost function of automatic generation control can be given by the following [1].

\[
\text{Cost of AGC} = f(\text{Heat rate degradation, Wear and tear of unit, Risk exposure})
\]

Since some of these quantities are hard to quantify, only the effects of heat rate degradation will be looked at in this thesis. This type of approach is called Alternative Regulation scenarios. The process involves two steps.

1. Designating Regulating Units (Capable of providing AGC. Synchronized to the System).
2. Block loading those units. The minimum and maximum output of the units is adjusted leaving some room for the Automatic Generation Control to pick up (or reduce) loading.

Under some special conditions AGC might work outside the Economical Dispatch of the System. These conditions can include emergency assist in case of unit or transmission line trips and other system disturbances. In these conditions AGC would raise the load on the fastest ramp-rate (MW / min) unit. The automatic generation control (AGC) controls the generation output of the units based on the incremental costs.

\[ \lambda_I \cdot PF_I = \text{Constant} = \text{System Lambda (System Incremental Cost)} \]  

where,

- \( \lambda_I \) = Incremental Cost of Generator "I"
- \( PF_I \) = Penalty Factor of Generator "I"

5.7. **Reactive Power Support (VAR Support):**

VAR represents the relationship of voltage and current at any point. It is a unit of measurement of reactive power. When the current and voltage are out of phase, the VARs are greater than zero. If the VARs are zero and power factor is unity, the current and voltage perfectly in phase.

VARs do not flow as power flows, but are indicative of a current-voltage phase angle relationship at a given location. The term "VAR flow" is used to represent the current-voltage phase angle relationship and the source of reactive components. Commonly, the bus is the reference for both real and reactive power comparisons. A
A meter indicating VARs "out" would be indicative of an inductive load with the bus (and contributing lines, generators and/or synchronous condensers) supplying the reactive component.

A meter indicating VARs "in" would be indicative of that line (and contributing generators, capacitors or synchronous condensers) supplying the reactive component to the bus (and the associated banks, load etc.)

VARs or Volt Amperes Reactive are needed on every system to support the less than unity power factor loads. If the loads are operating at units power factor, then there are no VARs required by that load. However most loads operate at less than unity power factor, thus increasing the need of the additional support in the form of reactive power.

Volt Amperes Reactive (VARs) are generally provided by two sources,

**Static VAR Compensators:**

Static VARs are supplied by capacitor banks on transmission and distribution systems. The capacitors are installed at proper distances and generally provide a constant source of reactive support on a system. However, due to changing demand of reactive support by the varying loads, there is still a need for dynamic on-line reactive power support.

**Dynamic VAR Support:**

This support is provided by generators, by utilizing the generators at less than unity power factor. The reactive power output of the generators is varied depending on the actual system requirements of reactive support.
CHAPTER 6:

CALCULATING COSTS OF ANCILLARY SERVICES

To evaluate the cost of providing three ancillary services including system security (Reserves), automatic generation control, and reactive power support, it is important to study operations of a power company. This chapter applies the principles of unit commitment and power system dispatch to calculate the cost of the three ancillary services. An arbitrary power company was created with the following fossil fuel generation stations, as shown in table 1 below.

<table>
<thead>
<tr>
<th>Unit Name</th>
<th>Fuel Type</th>
<th>Unit ID</th>
<th>Maximum Capacity</th>
<th>Minimum Capacity</th>
<th>Average Full load Heat Rate</th>
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<td>Nuclear #1</td>
<td>Fuel Rods</td>
<td>9</td>
<td>450</td>
<td>450</td>
<td>10.3580</td>
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<td>65</td>
<td>13.7700</td>
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<td>15</td>
<td>65</td>
<td>13.7700</td>
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<td>15</td>
<td>55</td>
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<td>60</td>
<td>60</td>
<td>14.0000</td>
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<td>Peaker #2</td>
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<td>60</td>
<td>60</td>
<td>14.0000</td>
</tr>
<tr>
<td>Peaker #3</td>
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<td>60</td>
<td>60</td>
<td>14.0000</td>
</tr>
</tbody>
</table>

Table 1: Fossil Fuel Generators

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In addition to the above fossil fuel generation, the company also controls two Hydroelectric Power Generation Plants, with specifications shown in table 2 below,

<table>
<thead>
<tr>
<th>Unit Name</th>
<th>Unit ID</th>
<th>Minimum Capacity</th>
<th>Maximum Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro #2</td>
<td>23</td>
<td>1</td>
<td>500</td>
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</tbody>
</table>

Table 2: Hydroelectric Generation

6.1. Case # 1: Base Case:

In this case the units were economically dispatched. Based on 10% of the company’s peak system load (3,500 MW), the operating reserves were set at 350 MW. According to NERC guidelines [8], half of the required operating reserves had to be spinning (Backed down generation). That required 175 MW of spinning reserves from the system. The resource allocation of different units to meet the system load is given in table 3 and chart 1 on the following pages,

System Dispatch Analysis:

The results of the system dispatch from table 3 are summarized below,

Nuclear Units:

It can be seen from the results that the Nuclear units are base loaded in the base case. This is expected due to efficient heat rate and low ramp rate of the Nuclear units.
<table>
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<th>Hour</th>
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<th>2:00</th>
<th>3:00</th>
<th>4:00</th>
<th>5:00</th>
<th>6:00</th>
<th>7:00</th>
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Table 3: Hourly Dispatch of Units (Base Case)
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Table 3 (Continued): Hourly Dispatch of Units (Base Case)
System Resource Allocation

Chart 1: Hourly Allocation of System Resources (Base Case)
Coal Units:
Coal units are backed down during the early morning (off-peak) hours. This is primarily due to availability of cheap purchase power during the off-peak hours. High cycling cost of these coal units also prevent from taking the units off-line during the off-peak hours. Low loading conditions during the early morning hours, due to minimal air conditioning load and no industrial load, also causes these units to back down.

Gas Units:
Two of the gas units (Gas # 1 and Gas # 2) are kept on-line for the off-peak hours due to high cycling costs. The other gas units come on-line as the load increases during the course of the day. The lowest point on the load curve corresponds to 6:00 am, due to coolest temperatures and the diminishing lighting load. The load starts picking up significantly after 8:00 am due to start of office hours and industrial load.

Gas # 3 comes on-line at 8:00 am followed by Gas # 4, Gas # 5 and Gas # 8 at 9:00 am. It can be observed that Gas # 6 and Gas # 7 were kept off-line, at this point in time, due to high heat rates of these units. Gas # 6 comes on-line for only one hour. 3:00 pm (15:00), at the peak load of 3,500 Megawatts. As the day progresses the load decreases, thus decreasing the need for expensive cycleable units. Gas units are taken off-line as the load decreases.

Hydroelectric Units:
Hydroelectric units are kept to the minimum load during the off-peak hours of the morning. The units pick up load as the system load increases during the course of the day. The dispatch of the hydroelectric units is dictated by the price of the replacement

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purchase power at any time. The units are optimized to use during the peak purchase
power (or generation) prices hours.

An important point to note in the operation of the hydroelectric units is that no
matter how these units are dispatched, the total Megawatt-hour produced during the day
stay the same. This limit is set by the Department of Energy (or some other non-utility
entity) to control the flow of water down the stream.

**REQUIRED AND ACTUAL SYSTEM RESERVES:**

Chart 2 on the following page shows the desired and actual system reserves,
plotted along the load curve.

From the actual reserves, it is clearly seen that both Operating and Spinning
Reserves are much higher than the desired reserves during the off-peak hours. This is due
to the effect of cycling costs and other base loaded units. Since the base loaded units are
kept on-line during the off-peak hours to avoid cycling costs, the actual reserves build up
unnecessarily.

The actual reserves are equal to the required reserves at the peak of system
load. This criteria can also be used to judge how good the system was dispatched during
the day. Higher actual reserves during the peak (than required reserves) determines
conservative (but uneconomical) operation of the system. Lower than required reserves,
on the other hand, dictate an unreliable operation of the system. Both of these conditions
ore not desired but may happen in the actual operation of the system.
Chart 2: System Load and Reserves (Base Case)
6.2. Case # 2: Selling Operating Reserves:

To calculate the price of providing operating reserves to some other company, the system had to re-dispatched to compensate for additional operating and spinning reserves.

In this case, the required operating reserves of the system are increased by 100 MW (Total 450 MW). This increase in operating reserves increased the required spinning reserves to 225 MW (Instead of previous 175 MW). The resource allocation of various units and purchases to meet this added criteria was different from the base case and is shown in table 4 and chart 3 on the following pages.

**System Dispatch Analysis:**

The results of the system dispatch from table 4 are summarized below.

**Nuclear Units:**

In this case the Nuclear Units are still base loaded as in the base case. This shows that, as expected, no reserves are being supplied by the Nuclear Units.

**Coal Units:**

The coal units are also dispatched similar to the base case, hence providing no contribution to the additional reserves.

**Gas Units:**

Just as expected, most of the additional reserves are being provided by additional gas units. As noticed in the base case, there were plenty of extra reserves available.
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Table 4 (Continued): Hourly Dispatch of Units
System Resource Allocation (Selling 100 MW Reserves)

Chart 3: Hourly Allocation of System Resources (Selling Reserves)
during the off-peak hours. During those hours the additional reserves were provided from the extra reserves available due to backed down generation.

During on-peak hours, the run of Gas # 6 (1 Hour in Base Case) was prolonged to 4 hours, to provide reserves to the buying company. Also another gas units, Gas # 7, was started for 2 hours to provide additional reserves. This change in operation of gas units during the peak hours increased the production costs of the system during those hours.

**Hydroelectric Units:**

Due to the nature of the hydroelectric units, no reserves are contributed by these units to the sale of the reserves. The dispatch of the hydroelectric units was similar to the base case.

**Required and Actual System Reserves:**

Chart 4 on the following page shows the desired and actual system reserves, plotted along the load curve.

**Results (By Comparison to Base Case):**

This change in the operation of the gas units due to additional reserve requirements resulted the following change in the total operating costs of the day.

- System Operating Cost (350 MW Operating Reserves) $1,024,352
- System Operating Cost (450 MW Operating Reserves) $1,026,209
- Change in the System Operating Costs $1,857
- Cost of Providing Reserves $18.57 / MW - Day
System Load and Reserves (Selling 100 MW Reserves)

CHART 4: System Load and Reserves (Selling Reserves)
The main reason for the low cost of operating reserves is that the dispatch of the units was changed for only 4 hours to provide the additional reserves. For other hours, significant extra reserves already existed on the system to compensate for the additional reserves.

Note that the above cost of providing operating reserves is the break-even cost and does not include any privilege charges (Profits) that any company might add on to the costs to compensate for real-life operation (versus computer simulation). The companies also need to compensate for the load forecasting error, since all prices for the reserves are decided prior to the operation of the whole day.

6.3. Case # 3: Buying Operating Reserves:

In this case the analysis for the reserve purchases will be done. Before the analysis, it can be predicted that this price should be substantially less than the total cost of providing reserves. This is mainly due to the fact that cheaper resources should be used for local system and provide reserves to the other companies based on incremental units.

In this case the operating reserves for the system are reduced by 100 MW (Total 250 MW). This increase in operating reserves increased the required spinning reserves to 125 MW (Instead of previous 175 MW in base case).

The resource allocation of various units and purchases to meet this added criteria was different from the base case and is shown in table 5 and chart 5 on the following pages.
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Table 5 (Continued): Hourly Dispatch of Units (Purchasing Reserves)
System Resource Allocation (100 MW Reserve Purchase)

Chart 5: Hourly Allocation of System Resources.
**SYSTEM DISPATCH ANALYSIS:**

The results of the system dispatch from table 5 are summarized below,

**Nuclear Units:**

In this case the Nuclear Units are still base loaded as in the base case. This shows that, as expected, no reserves were supplied by the Nuclear Units.

**Coal Units:**

The coal units in this case are dispatched slightly lower than the base case. This shows that some of the reserves for ourselves was coming from the coal units.

**Gas Units:**

In this case the generation from the gas units was reduced. Gas # 6 was completely taken off-line (Instead of one hour of operation in the base case). That also shows that the Gas # 6 was the most expensive incremental unit in the base case. This change in operation of gas units during the peak hours decreased the production costs of the system.

**Hydroelectric Units:**

The dispatch of the hydroelectric units still remained similar to the base case.

**REQUIRED AND ACTUAL SYSTEM RESERVES:**

Chart 6 on the following page shows the desired and actual system reserves, plotted along the load curve.
System Load and Reserves (Purchasing 100 MW Reserves)

CHART 6: System Load and Reserves (Purchasing Reserves)
RESULTS (BY COMPARISON TO THE BASE CASE):

This change in the operation of the gas units due to lower reserve requirements resulted in the following change in the total operating costs of the day.

- System Operating Cost (350 MW Operating Reserves) $1,024,352
- System Operating Cost (450 MW Operating Reserves) $1,023,639
- Change in the System Operating Costs $713
- Cost of Providing Reserves $7.13 / MW - Day

Just as expected, the price that should be paid for purchasing reserves is significantly lower than the price the reserves could be sold at. The forecasting and other real-life operation constraints should still be compensated for in the final price paid for reserves.

6.4. Case #4: Automatic Generation Control:

Since no additional units need to be committed for the Automatic Generation Control, the two gas units from the base case were taken (Gas #1 and Gas #2) and used to provide AGC for an external system. These units were picked because they were run all day in the base case. Also, it is assumed that these units are able to provide AGC and can be synchronized to the external system.

Based on the two units, the cost of providing +/- 60 MW (120 MW maximum load swing) of automatic generation control is to be computed. For that purpose the following restrictions were made to the system operation.

- 60 MW LOAD LOWERING:
Gas unit # 1:  Reserved output from 45MW to 15MW for external system (30 MW)

Gas unit # 2:  Reserved output from 45MW to 15MW for external system (30 MW)

+ 60 MW Load Increasing:

Gas unit # 1:  Reserved output from 55MW to 85MW for external system (30MW)

Gas unit # 2:  Reserved output from 55MW to 85MW for external system (30MW)

The above restrictions on the units will leave the units for output between 45MW and 55MW, for the local use. These restrictions will cost in terms of degradation in heat rate of the units as well as cycling. The cycling cost will depend on how much movement is desired by the other system. The AGC signal is sent every six seconds. If the units are required to move with almost every AGC signal, then the cycling costs will be maximized (Not very common case).

Such cycling costs of the units need to be determined by the contractual restrictions of providing AGC placed on the external system. These restrictions can dictate the cycling use of the units by the external company. Without such restrictions, the cycling costs will be computed for the worst case scenario i.e. the units are moved every six seconds to the maximum of their moving capacity (ramp rate per six seconds).

This case was run to provide AGC support of +/- 60 MW (120 MW maximum load swing). The results can then be compared to the base case. The resource allocation of various units and purchases to meet this added restrictions was different from the base case and is shown in table 6 and chart 7 on the following pages.

In order to understand the reasons for the costs of providing AGC, the operation of two units providing AGC needs to be looked at in further detail. The outputs and the incremental...
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<td>2078</td>
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<td>2000</td>
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<td>2436</td>
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Table 6: Hourly Dispatch of Units (Automatic Generation Control)
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<td>231</td>
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<td>737</td>
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Table 6 (Continued): Hourly Dispatch of Units (Automatic Generation Control)
System Resources (Gas 1 and Gas 2 on AGC)

Chart 7: Hourly Allocation of System Resources
Chart 8: Output of Gas # 1
Chart 9: Incremental Costs of Gas #1
Gas 2 Unit Output

Chart 10: Output of Gas #2
Chart 11: Incremental Costs of Gas #2

Gas 2 Unit Incremental Costs

Time of Day

- Gas 2 Without AGC
- Gas 2 With AGC
costs of the two units and the overall system are shown in charts 8, 9, 10, and 11 on the following pages.

**SYSTEM DISPATCH ANALYSIS:**

The results of the system dispatch from table 6 are summarized below.

**Nuclear Units:**

In this case the Nuclear Units are still base loaded as in the base case. This shows that, as expected, no reserves were supplied by the Nuclear Units.

**Coal Units:**

The coal units in this case are also dispatched similar to the base case.

**Gas Units:**

Due to the restrictions put on the Gas # 1 and Gas # 2 units, the dispatch of other gas units had to be changed to meet the internal system requirements. Gas # 6 was run for 14 hours (compared to one hour in the base case).

**Hydroelectric Units:**

The dispatch of the hydroelectric units still remained similar to the base case.

**Results:**

This change in the operation of the gas units due to lower reserve requirements resulted the following change in the total operating costs of the day.

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Operating Cost (350 MW Operating Reserves)</td>
<td>$1,024,352</td>
</tr>
<tr>
<td>System Operating Cost (450 MW Operating Reserves)</td>
<td>$1,031,830</td>
</tr>
</tbody>
</table>
Change in the System Operating Costs $ 7,478

Cost of Providing Reserves (per MW of maximum swing $ 62.32 / MW - Day

It should be noticed that the cost of providing AGC is much higher compared to the cost of providing reserves. The primary reason is that additional reserves are covered by the already existing extra reserves during the off-peak hours. The changes in dispatch of the units are only made during the peak hours, thus contributing to the additional system operating costs.

On the other hand, the AGC required the units to be restricted for the whole day. The cost of providing AGC can be significantly larger than the one calculated in this case, if an additional unit is started up for the additional support.

6.5. Costing VARs:

Calculating the cost of VARs generated or produced is different from the previous two methodologies. The reason for this is that VARs are produced by installing Capacitor Banks (To supple static VARs) and from Power Generators (To supply dynamic VARs).

**Static VAR Compensation:**

For static VARs, from the capacitor banks, the cost is the actual depreciation cost of a capacitor bank. Capacitor banks need very little maintenance, if any. For that reason, there are no operational costs. Static VAR compensation is needed usually on long transmission lines and industrial area distribution feeders. The effect of capacitor insertion is to improve the power factor, while decreasing the amps and VARs and
increasing voltage for a given load condition. Voltage and power factor are increased as inductive reactance and impedance are reduced by adding capacitors. Distribution capacitors are normally shunt connected units and may be connected in delta or wye configuration. Shunt capacitors may be installed in substations or could be pole mounted. Capacitors utilized in the Extra High Voltage (EHV) transmission are generally series connected.

The cost of this portion of the reactive power supply is simple calculated by the installation charges of a capacitor bank depreciated over the life of the bank. For example if a pad mounted capacitor bank of 1200 KVAR has a life expectancy of 30 years and total cost of installation of $20,000. Note that there might be components of the capacitor banks that might need replacement prior to the 30 year period. Those expenses will be counted as operations and maintenance expenses. For such a capacitor bank the cost of providing one VAR can be calculate as follows,

\[
\text{Cost} = \frac{20,000}{1200 \text{ KVAR} \times 30 \text{ Years} \times 365 \text{ Days/Year}} + O & M = 1.5 \frac{\text{Cents}}{\text{KVAR - Day}} + O & M \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (c)
\]

This is a over simplified calculation for the price of static VAR production.

**DYNAMIC VAR COMPENSATION:**

As previously discussed, dynamic VAR compensation is provided primarily by the generators. The need for the dynamic VAR support is to correct the ever changing power factor. New motors coming on-line, or running motors coming off-line and
drastically change the power factor for the rest of the system, if not properly compensated for.

No additional fuel is needed to generate the dynamic VARs. For that reason, the dynamic VAR production cannot be treated as an additional operating expense. The cost of producing dynamic VARs also comes from the equipment installed at the generators to follow and correct the power factor. Again in the case, the combined cost of all such equipment is depreciated over the average normal life expectancy of the equipment. Any maintenance expenses of such equipment is then added on to the depreciating value. This methodology covers the cost of installation of such equipment.

Based on various company policies, some error margin and profits might be added on to the combined cost of supplying static and dynamic reactive power support.
CHAPTER 7:

CONCLUSIONS

The cost of the three ancillary services was calculated one by one in the previous sections. The cost of providing system security (Reserves) was calculated by dispatching the system with and without the bought and sold reserves. This methodology provided a true value of providing or receiving reserves. To calculate the cost of Automatic Generation Control, the system was dispatched with restrictions on the ramping of the units providing the automatic generation control. This operation restricted the use of those units for the internal system use, thus raising the total operation costs. The delta change in operation of the restricted units provided the cost of automatic generation control. The cost of volt ampere reactive or reactive power support was calculated by the depreciating cost of the equipment and initial invest involved.

The methodology presented above is a generalized to a arbitrary utility company. However, the cases of individual companies will vary depending on the corporate goals and shareholder policies. In the calculation of all these ancillary services, only the break-even cost of providing these services was calculated. The whole section of Stranded Costs has been left on purpose since the methodology to recover stranded costs will vary from company to company.

This whole concept of un-bundling the ancillary services to create distribution, transmission and generation companies is still in very initial developmental stage. A lot of work is presently being done in various fields to study the feasibility of any such
actions. For the gas industry de-regulation, it has taken over 15 years and still there is some work being done to perfect the market based pricing systems.

From all the lessons learned from the gas industry de-regulation, the de-regulation of electric industry will be slightly faster than the gas industry. A lot of work still remains to be done in the area to get to the point of every utility's comfort. Still, there are critics who strongly oppose and argue that the direction of the electric industry's future is going to create worse monopolies rather than open market. They base their argument on the fact that the owners of large amount of transmission in any area can practically dictate the pricing in that particular area.

There are also consultants who argue that going to such market based pricing will make the industry unattractive for the new comers in the generation. No one will try to make the capital investments when they can predict that recovery of their investment will be very slow if not possible. Such a mindset will create shortage of electric energy capacities in the area, thus driving the price higher to make it more attractive for the new entries in the generation, transmission and distribution industries. Due to such pricing based on shortage of capacity, the FERC's original intention of price reduction to the consumers will be lost.

There are also groups who suggest that the comparison of gas and electric industries is not only unfair but also impossible. This is mainly due to one being a natural resource and the other being a generated product.

Aside from all these contrary beliefs and uncertainty among the consultants of electric utility industry, one thing remains the same. That is the goal to develop such a competitive market from which both the consumers and producers and benefit. As far as
the result of the deregulation goes, it can be anyone's guess to predict the future of the industry. However, a perfect solution can only be achieved if the deregulation is approached with the best of expertise and an open mind.
APPENDIX

CURRENT OPERATING RESERVE PRACTICES

OF REGIONS
<table>
<thead>
<tr>
<th>(1) REGION/</th>
<th>(2) RESERVE</th>
<th>(3) SPINNING RESERVE</th>
<th>(4) HOW IS IT ALLOCATED TO THE</th>
<th>(5) 10-MINUTE NON-SPINNING RESERVE REQUIRED</th>
<th>(6) HOW IS 10-MINUTE RESERVE ALLOCATED TO THE CONTROL AREAS?</th>
<th>(7) LARGEST UNIT IN REGION, SUBREGION</th>
</tr>
</thead>
<tbody>
<tr>
<td>SUBREGION</td>
<td>CRITERIA</td>
<td>(MW)</td>
<td>TO THE CONTROL AREAS?</td>
<td>(MW)</td>
<td>TO THE CONTROL AREAS?</td>
<td></td>
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<tr>
<td>ECAR</td>
<td>Control Areas</td>
<td>0.3 x Peak Load</td>
<td>Peak load (See formula)</td>
<td>0.3 x K x Peak Load (K=1)</td>
<td>Peak load (See formula)</td>
<td>Zimmer 1 (1300 MW) Rockport 2 (1300 MW)</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Control Areas</td>
<td>The ERCOT total responsive reserve requirement is the lesser of 2300 MW or the two largest units on line plus 200 MW whichever is less</td>
<td>80% based on their peak demand in the corresponding month of the previous year, 10% on the MW capacity of their largest unit on line, and 10% on the number of units over 200MW on line. These are all compared to the sum of all Control Areas' corresponding numbers.</td>
<td>No 10 minute reserve criteria.</td>
<td>Not Applicable</td>
<td>1250 MW South Texas Project Unit 1 and Unit 2</td>
</tr>
<tr>
<td>MAAC</td>
<td>Region (PJM Interconnection Control Area)</td>
<td>Largest unit on line (usually 1100 MW), but no less than 700 MW</td>
<td>Only one Control Area, so no allocation.</td>
<td>1700 MW</td>
<td>Only one Control Area, so no allocation.</td>
<td>Limerick 2 (1115 MW)</td>
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<td>REGION/SUBREGION</td>
<td>RESERVE CRIERIA APPLIES TO?</td>
<td>SPINNING RESERVE REQUIRED (MW)</td>
<td>HOW IS IT ALLOCATED TO THE CONTROL AREAS?</td>
<td>HOW IS 10-MINUTE NON-SPINNING RESERVE ALLOCATED TO THE CONTROL AREAS?</td>
<td>LARGEST UNIT IN REGION, SUBREGION</td>
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<td>---------------------------------</td>
<td>------------------------------------------</td>
<td>------------------------------------------------</td>
<td>--------------------------</td>
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</tr>
</tbody>
</table>
| MAIN             | MAIN, with allocation to individual Control Areas and/or members | 1/2 gross rating of the largest unit operating (or largest other resource) in MAIN + Sum of the Adequate Regulating Margin for each MAIN member | Operating Reserve, not spinning reserve, shall be distributed among the member systems or Control Areas as follows:  
• Each Control Area shall have as a part of its required Spinning Reserve the amount of reserve which is sufficient to provide Adequate Regulating Margin for that system.  
• 50% of the Operating Reserve requirements, excluding the sum of the individual systems’ Adequate Regulating Margins, shall be distributed in proportion to each member’s actual previous calendar year peak demand to the actual non-coincident peak demand of MAIN, and  
• 50% of the Operating Reserve requirements, excluding the sum of the individual systems’ Adequate Regulating Margins, shall be distributed in proportion to the highest normal gross rating of the Largest Resource in commercial service in each member’s system or Control Area to the sum of the ratings of the Largest Resources in commercial service in each of the MAIN systems or Control Areas. | 1/2 gross rating of the largest unit operating (or largest other resource) in MAIN | See column 4 |
<p>| Callaway (U/E)   | Byron (ComEd) 1120 MW net (1232 MW gross) (operating reserve based on gross rating) | Braidwood 1,2 (ComEd) 1120 MW net | | | |</p>
<table>
<thead>
<tr>
<th>(1) REGION/ SUBREGION</th>
<th>(2) RESERVE CRITERIA APPLIED TO?</th>
<th>(3) SPINNING RESERVE REQUIRED (MW)</th>
<th>(4) HOW IS IT ALLOCATED TO THE CONTROL AREAS?</th>
<th>(5) 10-MINUTE NON-SPINNING RESERVE REQUIRED (MW)</th>
<th>(6) HOW IS 10-MINUTE RESERVE ALLOCATED TO THE CONTROL AREAS?</th>
<th>(7) LARGEST UNIT IN REGION, SUBREGION</th>
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<tbody>
<tr>
<td>MAPP</td>
<td>Region</td>
<td>MAPP Operating Reserve Requirement (MORR) total is 150% of the MW value of the largest unit on line, or 100% of the MW value of generation that would be lost following worst transmission contingency (Canadian 500kv line), whichever is larger. Spin must be at least one-half of that amount, with the remainder available in 10 minutes or less.</td>
<td>Allocated per member on the basis of 1/3 largest unit and 2/3 peak load as a percentage of total of largest units &amp; peak loads. Not all members are Control Areas. MORR is in addition to reserves needed for regulation.</td>
<td>No more than 2 MORR (See column 3) Qualifying interruptible can be used for non-spinning reserve</td>
<td>(See column 4)</td>
<td>Sherco 3 at 874 MW</td>
</tr>
<tr>
<td>NPCC</td>
<td>Five Areas New York, New England, Ontario Hydro, Hydro Quebec, &amp; Maritime</td>
<td>(25 to 1) x (First Contingency Loss)</td>
<td>(25 to 1) x (First Contingency Loss)</td>
<td></td>
<td></td>
<td>New England Area: Phase II HVDC tie at 1400 MW New York Area: Nine Mile Point unit 2 at 1130 MW Quebec Area: one transformer at Churchill Falls (1000 MW) Ontario Hydro Area: one Darlington Unit at 930 MW Maritime Area: Point Lepreau unit at 680 MW</td>
</tr>
<tr>
<td>REGION/SUBREGION</td>
<td>RESERVE CRITERIA APPLICABLE?</td>
<td>SPINNING RESERVE REQUIRED (MW)</td>
<td>HOW IS IT ALLOCATED TO THE CONTROL AREAS?</td>
<td>10-MINUTE NON-SPINNING RESERVE REQUIRED (MW)</td>
<td>HOW IS 10-MINUTE RESERVE ALLOCATED TO THE CONTROL AREAS?</td>
<td>LARGEST UNIT IN REGION, SUBREGION</td>
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<tr>
<td>SERC (FLORIDA)</td>
<td>Florida Subregion</td>
<td>25% of the largest unit online or approximately 227 MW</td>
<td>Reserve requirement is based 50% on the proportionate share of the total peak energy of the previous year and 50% on the proportionate share of the sum of the largest units in each Control Area.</td>
<td>Same basis as the spinning reserve i.e. 50%</td>
<td>Same basis as the spinning reserve i.e. 50%</td>
<td>St. Lucie 1 or 2 at 910MW (gross)</td>
</tr>
<tr>
<td>SERC (SOUTHERN COMPANY)</td>
<td>Control Area</td>
<td>0.75 x Largest unit online</td>
<td>To all Control Areas</td>
<td>0.75 x Largest unit online</td>
<td>To all Control Areas</td>
<td>1,200 MW - both Vogtle 1 &amp; 2</td>
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<tr>
<td>SERC (TENNESSEE VALLEY AUTHORITY)</td>
<td>TVA Subregion</td>
<td>Largest unit online plus load following = 1450 MW Spinning Reserve=0.5 x (1450 MW) = 725 MW.</td>
<td>Allocated all to TVA Control Area</td>
<td>725 MW</td>
<td>Allocated all to TVA Control Area</td>
<td>Cumberland 1 and Cumberland 2</td>
</tr>
<tr>
<td>SERC (VACAR)</td>
<td>VACAR Subregion</td>
<td>Total Contingency Reserve is equal to the largest singular resource in the combined areas of VACAR multiplied by 1.5. Each utility will also maintain a Contingency Reserve Capacity, which can include: Unloaded, synchronous capacity, 10 minute non-spinning capacity, Interruptibles (within 10 minutes), Available new capacity.</td>
<td>Each company's allocation of the Total Contingency Reserve is based on an average of: Each company's peak load as a percentage of the total VACAR peak load, and Each company's largest resource as a percentage of the sum of the largest resources of each VACAR company.</td>
<td>See column 3</td>
<td>See column 4</td>
<td></td>
</tr>
<tr>
<td>SPP</td>
<td>Region</td>
<td>1/2 (50%) of Largest 1&amp;1/2 Units scheduled for service (see column 7)</td>
<td>Pro-rated based on Control Area's Peak Load Obligation of the previous day</td>
<td>1/2 (50%) of Largest 1&amp;1/2 Units scheduled for service (see column 7)</td>
<td>Pro-rated based on Control Area’s Peak Load Obligation of the previous day</td>
<td>Largest Unit: 1166 MW, Next largest: 1054 MW</td>
</tr>
<tr>
<td>(1) REGION/</td>
<td>(2)</td>
<td>(3)</td>
<td>(4)</td>
<td>(5)</td>
<td>(6)</td>
<td>(7)</td>
</tr>
<tr>
<td>SUBREGION</td>
<td>RESERVE</td>
<td>SPINNING</td>
<td>HOW IS IT ALLOCATED TO THE</td>
<td>10-MINUTE</td>
<td>HOW IS 10-MINUTE</td>
<td>LARGEST</td>
</tr>
<tr>
<td></td>
<td>CRITERIA</td>
<td>RESERVE</td>
<td>THE CONTROL AREAS?</td>
<td>NON-SPINNING</td>
<td>RESERVE ALLOCATED</td>
<td>UNIT</td>
</tr>
<tr>
<td></td>
<td>APPLIES TO?</td>
<td>REQUIRED</td>
<td>(MW)</td>
<td>RESERVE REQUIRED</td>
<td>TO THE CONTROL AREAS?</td>
<td>IN</td>
</tr>
<tr>
<td>WSCC</td>
<td>Reserve criteria</td>
<td>Sufficient spinning reserves</td>
<td>Each Control Area must have sufficient spinning reserve to provide adequate regulating margin and meet NERC's performance criteria, plus 50% the greater of: * Largest contingency (transmission or unit) * 5% of load supplied by hydro and 7% of load supplied by thermal generation.</td>
<td>No more than half of the 5% or 7% requirement must be responsive within 10 minutes, plus additional reserves, available in 10 minutes, equal to non-firm imports, plus additional reserves, available in 10 minutes, equal to on demand obligations to others. Non-spin can be met by the use of the following: * Interruptible load * Interruptible exports * On demand rights from others * Excess spinning reserve * Off-line generation</td>
<td>See column 4.</td>
<td>The largest contingency (generation or transmission) is that of each Control Area within the WSCC unless the Control Areas combine or share their reserve requirements</td>
</tr>
</tbody>
</table>

Under written agreement, the operating reserve requirements of two or more Control Areas may be combined or shared or one Control Area may supply a portion of another's operating reserve, providing it can be made available in the required time and response rate. Load responsibility is defined as the system or area firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier.
<table>
<thead>
<tr>
<th>REGION/ SUBREGION</th>
<th>COMMENTS</th>
</tr>
</thead>
<tbody>
<tr>
<td>ECAR</td>
<td>No comments</td>
</tr>
<tr>
<td>ERCOT</td>
<td>Control Areas may fulfill up to 35% of their requirement (as long as the total is less than 25% of the ERCOT requirement) with high-set underfrequency interruptible load that automatically trips at 59.7 Hz or above or hydro capacity acting as synchronous condenser that can convert to generating mode within 10 seconds. Control Areas may also purchase up to the greater of 25 MW or 25% of their requirement from other Control Areas. ERCOT is in the process of changing its reserve definitions.</td>
</tr>
<tr>
<td>MAAC</td>
<td>MAAC Region has accepted PJM operating procedures as appropriate because PJM is the only Control Area in the region and covers the entire region. Also, PJM uses the term &quot;Primary Reserve&quot; for spinning and quick start available in 10 minutes, and Operating Reserve for reserve in 30 minutes.</td>
</tr>
<tr>
<td>MAIN</td>
<td>See MAIN Reserve Guidelines</td>
</tr>
<tr>
<td>MAPP</td>
<td>Spin may be sold to another MAPP member as economy energy, but the buyer must maintain his own spin plus amount equal to the purchase. Such a sale is immediately cancelable. Under the new MAPP Agreement, the allocation will be based on something else; a combination of end-use load and firm sales. MAPP uses an automated process called the Emergency Replacement program which keeps track of MW, integrates hours, and produces a total for the event. (MW only, not $)</td>
</tr>
<tr>
<td>NPCC</td>
<td>MA MAIN Reserve Guidelines</td>
</tr>
<tr>
<td>SERC (FLORIDA)</td>
<td>No Comments</td>
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<tr>
<td>SERC (SO, CO2)</td>
<td>No comments</td>
</tr>
<tr>
<td>SERC (TVA)</td>
<td>No comments</td>
</tr>
<tr>
<td>SERC (VACAR)</td>
<td>No comments</td>
</tr>
<tr>
<td>SPP</td>
<td>During emergency Operating Conditions, the Operating Reserve requirement may be increased to the 2 largest units. The Operating Reserve Criteria implementation utilizes a dedicated computer communications network.</td>
</tr>
<tr>
<td>WSCC</td>
<td>Various Power Pools within the WSCC have reserve sharing agreements that meet the WSCC requirements plus any local requirements.</td>
</tr>
</tbody>
</table>
BIBLIOGRAPHY


[7]. NERC “Comments of the North American Electric Reliability Council”. NERC’s Comments to FERC with respect to the open-access NOPR).

[8]. NERC “Glossary of Terms” A collection of definitions published by the NERC Engineering and Operating Committees in August, 1996.

