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# SOME TOPICS ON THE DEREGULATION OF THE POWER INDUSTRY IN THE UNITED STATES

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## Preface

This is a student report prepared for **EE635**, Economic Operation and Control of Interconnected Power Systems, for the Spring, **1992** semester at Purdue University. The assigned topic to the class was to discuss and describe some aspects of the "deregulation" of the United States power industry. The first chapter by Charles Thompson deals with the wheeling and transmission losses due to power exchange. This topic has been a main bottleneck for accountants and engineers in fully realizing advantages in a deregulated power environment. Perhaps the core of deregulation, the Public Utility Regulatory Policies Act (PURPA), is discussed and described by Patrick Lyons in Chapter **II**. A description of the **1978** act, its amendments, and a commentary on the act is presented.

The third and fourth chapters deal with demand side management (DMS). Chapter **III** by Ramanujam Ramabhadran focuses on the industrial sector and Chapter **IV** by Kevin Karagory moves to the residential and commercial sectors.

The last chapter deals with one small element of control of power flow in the transmission network. This is the use of high voltage DC systems for power flow control. The chapter describes HVDC systems in general and their control possibilities. Mr. Paul Ruby, the author of the chapter, is working in the solid-state area. For this reason, some special emphasis is made on *devices* in this chapter.

Although this report is an incomplete sampling of topics on consequences of PURPA and "deregulation," it is meant to be an introduction to the topic and a brief but representative sampling of topics in this complex area.

G. T. Heydt  
EE635 Instructor  
April, 1992

## **Chapter I Wheeling and Transmission Losses Due to Power Exchange by: Charles A. Thompson**

### **I.1 Introduction**

In 1978, the first step toward the deregulation of the United State's power systems was initiated with the passing of the Public Utilities Regulatory Act (PURPA). In essence, PURPA set way for competition in the bulk power markets from qualified generating facilities such as industrial cogenerators and certain classes of small power producers [1]. A second initiative by the Federal Energy Regulatory Commission (FERC) was to issue three Notices Of Proposed Rule-makings (NOPR's) in March 1988. These rules, should they come about, clarify means for defining prices that franchised utilities must pay when purchasing electricity and capacity for qualifying facilities (QF's). These NOPR's also set bidding guidelines (for Electricity) and defined the operation of independent power producers (IPP's) [2]. The effects of these acts and rulings was to cause a more invested interest in the private production of electricity. This, in turn, has created much concern with providing transmission access to these QF's. In particular, a means of charging wheeling rates and attributing transmission losses has been a recent hot bed of debate.

### **1.2 Wheeling power**

Wheeling has been defined as: "the use of transmission or distribution facilities of a system to transmit power of and for another entity or entities." [3] For example, entity "A" would like to purchase power from entity "C". But the connection from "A" to "C" passes through entity "B". Therefore, the power sold from "C" to "A" must pass through "B"--it is said that power is "wheeled" through "B". In essence "C" sells the power to "B" who in turn sells the power to "A" (attaching a wheeling charge for transmission access). Figure I.1 shows an example of a how a system like this may be constructed.

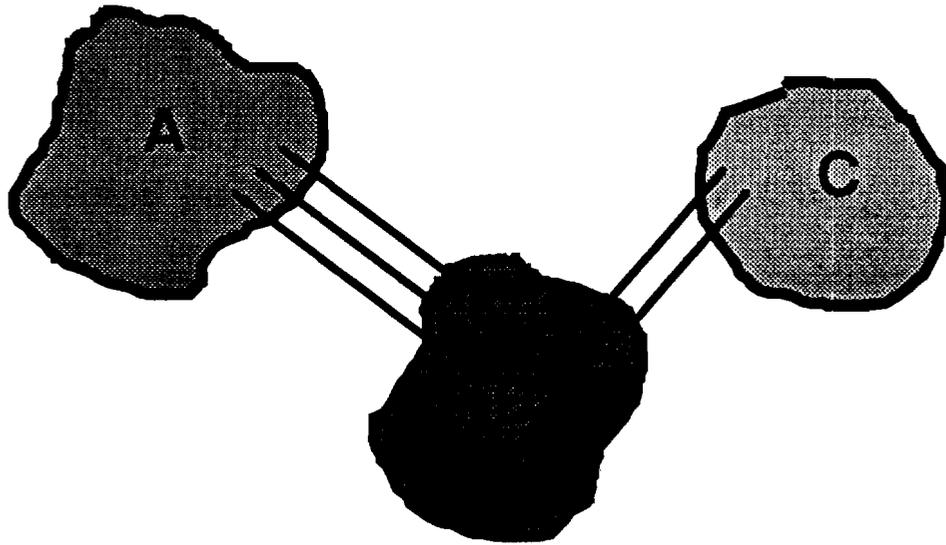


Figure 1.1 Simple wheeling topology (B is the intermediate (wheeling) utility).

The four common types of wheeling transactions are:

- 1) Utility to Utility
- 2) Utility to Private User
- 3) Private Generator to Utility
- 4) Private Generator to Private User

'Wheeling power between utilities is a common practice today. Most agreements for wheeling charges are worked out fairly routinely without a great deal of trouble. However, increased interest in **IPP's** can raise the complexity of power wheeling dramatically. Suppose entity "C" in the above example is a private generator and entity "A" is a private user. In this case entity "B" would most likely be the local utility. One reason "A" may wish to purchase power in this way might be that "C" may sell power cheaper than "B". As more private generators come on line, the complexity of balancing power transactions in this manner greatly increases. Not only will the increase in generation cause problems with balancing power transaction, the competition created will introduce more difficulties in the **number** of power purchasers who purchase power from the **IPPs**.

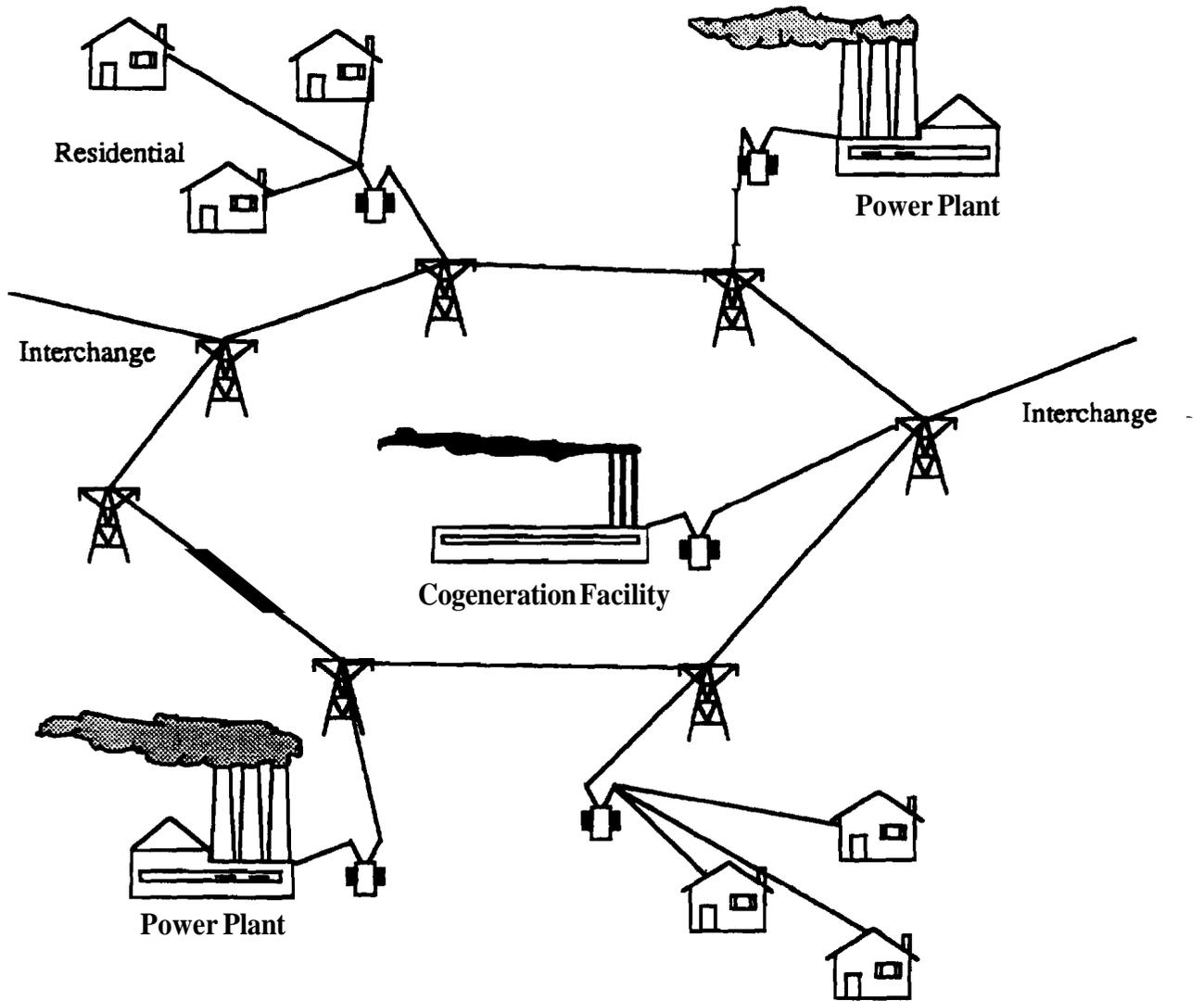


Figure 1.2 Simplified power system (based on [2]).

## I.4

There are many debatable aspects in the wheeling of power. These issues are presented **very** briefly in [4]. One issue of debate is who should share the benefits of wheeling. For **instance**, should the intermediate utility (the middle guy) gain from wheeling power from one utility to another. If so, by how much? Another issue is what **cost-risks** should the wheeling utility recover. Debates in this area are focussed on whether the wheeling utility **should** add additional charges for maintenance and upkeep costs, as well as **additional** costs of assuring system stability and security. Some forms of system stability protection measures might be the addition of transmission lines or even **VAR** compensators. **VAR** compensators may be required to balance power factors that may decrease due to the increased use of the transmission lines by the wheeling transactors.

There are also debates as to the how often to modify wheeling rates. There is some concern that wheeling rates be modified in near real time to reflect the **changes** in operating conditions. A more accurate cost assessment can be made if the rates were **modified** in real **time**, however do to so incurs certain penalties in algorithm (software) **complexity** to handle such a problem, as well as computation speed. Computation speed **becomes** a critical issue **when** a power system is **too** complex to perform calculations in near real **time**. The addition of **IPPs** and such would even complicate an already difficult problem. In (addition to **all** of this, an ideal program (software) should take into account certain environmental conditions as well. To increase the performance of a system variables, such as **temperature** and **humidity**, should be introduced into the software so that overloading does not present itself as a problem. The warmer the day, the lower the transmission capability **will** be...this may prove an important factor when trying to maximize the number of users of a transmission system.

And a final question for debate is: "Is wheeling the first step towards a deregulated utility system?" The issue of the deregulation of the US power system has been a recent hot bed of activity. There are many forces pushing for deregulation **claiming** economic and quality benefits. Yet there are those in the opposition who claim the opposite would result. Although this debate is of great importance to the future of wheeling transactions, this paper will not dwell on the politics involved in the deregulation.

Both wheeling and non-utility generation (**NUG's**) options affect vital **attributes** such as system security, voltage profile, losses and **VAR** reserves. These options **also** put strain on the existing transmission system and may restrict economic utility **dispatching**[6]. The wheeling of power and the use of **NUG's** poses problems with maintaining system security. A transmission network which may be inherently secure might suffer serious problem if **power** is being wheeled across lines and the utility suffers a contingency. Such an event

could cause the power lines carrying the wheeled power to become overrated and thus become an outage as well. And, in turn, this could cascade throughout the network.

System security is one of the large concerns in the wheeling of power. Typically utilities have established agreements which dictate the type of security the utility has. Security is basically the system's immunity to the interruption of power to the customer (power outage). Should a generating unit go down or a transmission line fail, each utility has established procedures to curtail any problems this may incur. For example, a utility is required by the North American Electric Reliability Council (NERC) to maintain a certain percentage of spinning reserve should a generating unit fail. Spinning reserve is basically a unit, or units, which is kept spinning at the nominal 60Hz rate and which can be brought on line in a relatively short amount of time. Utilities also have the ability to redispatch units in the event a transmission line should fail. This allows a utility to shift generation to minimize the loading on the lines which are in close proximity to the fault (to prevent these lines from overrating). Although this does not result in an optimum operation, it does circumvent line failures from propagating through the system.

Wheeling utilities pose certain problems to the stability of power systems. In some sense, IPPs can be thought of as non-dispatchable generators (in most cases the local utility has little or no control of the dispatch of these IPPs -- except for contractual obligations). Should a transmission line go down in the region of an IPP, there would be no automatic means of completely redispatching the system due to this uncontrollable power producer. Therefore the security of the system is compromised because, in a sense, the utility does not have complete control on the power carried on the transmission lines. Since the IPP is not directly controlled, a contingency could result in the **IPP** shipping power across lines which may result in an overload. Once this occurs, these lines could trip and cause other lines to overload. These outages could cascade throughout the whole system.

Another concern about the IPPs is that since utilities are required to maintain a certain reserve margin, do the utilities need to maintain the reserve margin based on the utility's generation levels, or the load level supplied by the utility's transmission lines? Should the utility have to maintain the margin which would correspond to the IPPs generation, or should the **IPP** be required to maintain this margin in some way?

Maintaining a voltage profile is also an important requirement. Wheeling of power can induce fluctuations in voltage levels at certain busses. Such fluctuations could come about from a change in unit dispatch (to maintain an economic system profile). Maintaining this voltage profile would most likely come in the form of adjusting **transformer** taps.

Wheeling power may also introduce the need for **VAR** compensation. These **compensators** would be needed improve the quality factor of a line should **the** wheeling of **power** cause problems....

Since a transmission system is composed of numerous conductors (**many** of which run in "parallel" with each other), no one conductor can be picked to carry power from one place to **the** next. In essence all conductors carry a portion of this power. So, the weakest link in the system is dictated by the transmission line which would fail first. Although the entire transmission system may have an extremely large capacity, the whole system is limited by its weakest link. The final concern of wheeling power is the attribution of **losses** within the **system**. Since shipped power moves through all parallel lines, **transmission** losses will increase within the wheeling utility as well as close neighboring utilities. **These** utilities will experience transmission losses simply because of the highly interconnectedness of the US **power** grid.

### 1.3. Transmission Losses

**Transmission** losses are characteristically non-linear in nature. The major component **taken** into **account** is the  $I^2R$  (ohmic) losses in the line. As the power wheeled increases, the **losses** due to transmission increase as well (roughly the losses **are** of similar order to the power interchanged). These losses **are** fairly difficult to **calculate--especially** since many **systems** lack metering devices between utilities to monitor power flows. Some method of **determining** losses due to wheeling must be used to accurately charge the appropriate entity (this is another issue of debate).

One means of evaluating wheeling **transaction** effect on a system, and the transmission **losses** incurred, is to use an Optimal Power Flow (OPF). This concept, along with example scenarios, is presented in [6]. Basically, the OPF can model the generation and transmission system quite accurately for discrete moments. An OPF will **also** calculate **VAR** **requirements**, bus voltages, and transmission losses.

**Another** means of evaluation wheeling transactions is presented in [3] and [4]. This **method** involves the use of the Marginal Cost Theory (incremental costs-- **lambda**) coupled with the short term cost of wheeling (the incremental cost for the last MW of power wheeled).

The program WRATEs has been written to improve means of **evaluating** wheeling **transactions** [4]. WRATEs (which is an acronym for: Wheeling **RATes** Evaluation simulator) is a PC based program that calculates the wheeling rate which should be charged **based** on the Marginal Operating costs as well as Revenue Reconciliation **adjustments** for capital recovery [4]. The ideal wheeling rate varies as the spot prices of electricity change

[3]. Transmission constraints and modeled within the program such that events which would cause an overload would rise the wheeling rate such that this event would be discouraged. In addition the wheeling rate could go negative should wheeling cause a decrease in transmission losses.

There is one problem associated with the use of this software. The problem is to decide how much capital should be recovered as part of the reconciliation adjustments. There is no good theory which dictates this amount. In fact, this will prove to be a highly debatable topic. For example, should a utility be able to claim capital recovery for a generation facility which is unused due to loss of sales to wheeling power?

#### **1.4 Possible scenarios**

In 1989, the 101st Congress Office of Technology Assessment published a report on electric power wheeling [2]. This report listed five possible scenarios for the future of electric power wheeling. A review of these scenarios appears below.

##### **Scenario 1 *Strengthening the regulatory bargain***

This scenario differs from the status quo by a very small amount. The major difference is a slight modification of the present regulatory process. Changes would be made so that states would reduce the investment risk for new construction. The PURPA act would also have to be modified to address perceived imbalances in the implementation of avoided cost pricing for QF payments. And finally, incentives which would encourage the construction of additional transmission capacity.

Utilities would still remain the primary providers of electric power. Co-generators and **IPPs** would still be capable of competition, however they would not receive preference under state and federal regulation.

##### **Scenario 2 *Expanding transmission access and competition within the existing institutional structure.***

Scenario 2 would expand the competition in generation sector by increasing the number of power sellers by modifying some of the size, technology, fuel, and ownership limitations for **QFs** under PURPA. Also, transmission access would be under the authority of the **FERC**. Therefore, if a power producer is denied access to a transmission system, this power producer can take the case to **FERC**. The utility refusing access would then have to prove there is a lack of available capacity in their system, or that by accommodating the

wheeling transaction the utility's service would be degraded. The utility would **receive** just **compensation** for **providing** transmission access.

**Scenario 3** *competition for new bulk power supplies*

Under scenario 3, if **additional** power generation is needed, the utility requesting the additional generation would solicit proposals to supply it. The utility would select the best bids from other utilities and **QFs** (based on various factors, including cost), **set** up a contract with the generation facility, and then transmit this power through the utility's network. Regulation of the utilities in scenario 3 would essentially be the same as the **present**.

**Scenario 4** *Competition for all bulk power supplies*

Scenario 4 would restructure the industry in a much shorter time than **scenario 3**. This scenario would require the segregation of generation facilities from **transmission** and distribution facilities (transmission and distribution could be either the **same or** separate **identities** under this scenario). The intention of scenario 4 is to impose **regulations** on the **transmission** and distribution facilities such that these entities would **be** required to meet the load. The transmission and distribution entities would be required to contract with generation facilities in order to supply power to its customers. It would **also** be through contract that the facilities would dispatch power. This scenario **would** produce high competition for generation rights by all **QFs**. Wheeling for retail customers would be strictly voluntary.

**Scenario 5** *Common carrier transmission services in a disaggregated market-oriented, electric power industry.*

**Scenario 5** would completely segregate the power system as it is known today. It would break the power industry into three separate entities: power generation, **transmission**, and distribution. All customers would have the option of purchasing power from any willing supplier. Distribution and transmission services would remain tightly regulated, however, **prices** for generation would be **primarily** left to market forces and **competition**.

The above scenarios represent the Office of Technology Assessment's **best** estimate of **what** the future of electric power generation, transmission, and distribution holds. There are, of course, many other possibilities (and these **should** not be discounted.). However, to

obtain a decent understanding of what the future may hold, these scenarios provide a detailed picture.

## **Summary and Conclusions**

The purpose of this paper was to present the problems associated with the wheeling of power and what losses may occur as the result of this wheeling. An additional purpose of this paper was to explore some of the present thoughts on wheeling as well as what future affects power wheeling may have.

Wheeling power is certainly a complicated act. Due to the complexity of power systems in the United States, assessment of optimal operation is quite difficult. ~~The~~ addition of independent power producers and retail power customers will further complicate this already sophisticated system. Much more research is needed to examine the effects of power wheeling on the local utilities. Knowledge of transmission losses within as well as outside the wheeling utility. Only when a good knowledge of losses is understood, can charges be applied appropriately.

In addition to charging for transmission losses, knowledge of wheeling effects on the system will allow a better understanding of line loading throughout the utility. Much concern has been expressed about compromising system security in order to allow wheeling transactions to take place. Once a better understanding of wheeling effects is gained, then proper counter-measure can be implemented.

Finally, it is necessary to study the possible scenarios for the future. This is necessary so that the most promising future can be sought, Although bureaucracy can impede any attempted plan, at least a step in the right direction will help.

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## Chapter II

### The Public Utility Regulatory Policies Act of 1978

Patrick G. Lyons

#### II.1 Introduction

Prior to the 1970's, utilities enjoyed a relatively **competition-free** industry with steady growth and a decreasing cost curve. With the 1970's came the energy crisis which led to the conservation of energy becoming a major concern of the United States during this time. Out of these changing times was born the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA's main function was to allow for alternatives to the central generating station by encouraging cogeneration. Cogeneration refers to the production of electric energy and useful thermal energy, such as heat or steam, through the sequential use of energy. For example, in industrial or commercial plants, where heat or steam is needed, some of the otherwise wasted energy can be put to use to generate electricity [2]. PURPA set the stage for independent power producers and other **non-utility** generators to enter the power industry by forcing utilities to consider **'non-utility generation'** when planning to install new **generation**.

PURPA covers several broad areas. The first two sections cover policies for electric utilities and

## II.2

authorities of federal and state agencies over electric utilities. The other sections of PURPA cover policies for natural gas utilities, crude oil transportation, and small hydroelectric projects. These will be touched upon lightly in this chapter. The majority of this chapter will be: a presentation of the Public Utility Regulatory Policies Act of 1978; a brief discussion of the amendments to PURPA since 1978; an interpretation of the major points of PURPA and their effects on utilities; and an explanation of new ideas on how to calculate avoided costs for utilities.

### II.2 Regulatory Policies for Electric Utilities

The main function of PURPA is to define a set of rules for the operation of utilities which encourages energy conservation and cogeneration. PURPA itself is about 56 pages of legal linguistic acrobatics and only the main points will be paraphrased and discussed in the following pages [1].

The authoritative bodies, whose job it is to enforce PURPA, are the Federal Energy Regulatory Commission (FERC), the Department of Energy, and the Secretary of Energy on the national level and the State regulatory authorities on the state level. FERC is able to enforce the laws set forth, but ratemaking authority is delegated to the State regulatory authorities. It will be quite obvious in the discussion of PURPA that the regulations set forth are very

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general and the specifics are left up to the State regulatory authorities.

The heading of Title I is "Retail **Regulatory** Policies for Electric Utilities." Section 101 states the purposes which this title is to encourage. These purposes are to encourage-

- (1) conservation of **energy** supplied by electric utilities
- (2) the optimization of the efficiency of use of facilities and resources by **electric** utilities; and
- (3) equitable rates to customers.

All rules and regulations described within PURPA are designed to promote these purposes.

Section 102 states that before the beginning of each calendar year, the Secretary of Energy shall publish a list identifying each electric utility to which this title applies during the present calendar year. This list is then passed on to the State regulatory **authorities** and the utilities themselves.

Sections 111 and 115 establish certain general federal standards. These standards apply to each of the **utilities** on the list and also non-regulated utilities. The following descriptions provides a **brief** overview of each of the different areas [1].

(1) Cost of Service - Rates charged by an electric utility shall be designed to reflect the cost of **providing**

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## 11.4

electric service to each class of customers. The costs shall be determined on the basis of methods **prescribed** by the State regulatory authority. These methods shall:

(a) identify differences in cost-incurrence, for each class of electric consumers, attributed to daily and seasonal time of use and attributed to differences in customer demand.

(b) take into account the extent to which the total cost to the utility are likely to change if **additional** capacity is added to meet peak demand and additional kilowatt-hours are delivered are **delivered** to electric customers.

(2) **Declining Block Rates** - An electric utility may not decrease its rate to any class of electric consumer during a given time period as the kilowatt-hour consumption of that consumer increases, unless the utility can demonstrate that its costs will decrease during that time period as that customers consumption increases.

(3) **Time-of-Day Rates** - The rates charged by an electric utility to **each** class of electric consumer will reflect the cost of providing that electric service at different times of the day, unless such rates are **not** cost-effective.

(4) **Seasonal Rates** - The rates charged by an electric utility to each class of electric consumer will reflect the **cost** of providing that electric service at different seasons of the year, unless such rates are not **cost-effective**.

It can be seen in the previous two sections that these regulations are quite general. Terms such as "cost effective" are left open to interpretation to each State regulatory authority and may be interpreted differently in different states.

(5) Interruptible Rates - Each utility shall offer each industrial and consumer customer an interruptible rate which reflects the cost of providing interruptible service to that class of consumer.

(6) Load Management Techniques - Each utility shall offer its customers load management techniques which are cost-effective, reliable, and provide useful energy management advantages to the electric utility. The State regulatory authority shall rule a technique cost-effective if-

- (a) it reduces maximum kilowatt demand on the electric utility; and
- (b) there are long-run cost savings which exceed the long-term costs associated with this technique

(7) Automatic Adjustment Clauses - These are provisions of a rate which provide for an increase or decrease in rates, without prior notice, reflecting an increase or decrease in costs incurred by an electric utility. These are reviewed every two to four years by the State regulatory authority and approved if they provide incentive for efficient use of resources.

## 11.6

(8) Information to Customers - Each electric utility shall transmit to each of its electric customers a clear and concise explanation of the existing rate schedule and any new rate schedule applied for by that customer.

(9) Procedure for Termination of Electric Service - These procedures are determined by the State regulatory authority, but must provide that

(a) no electric service to a customer may be terminated unless reasonable notice is given along with notice of rights and remedies.

(b) electric service to a customer may not be terminated if the State regulatory authority determines it would be especially dangerous to health and the customer establishes that he is unable to pay for the service, or only able to pay in installments.

(10) Advertising - Utilities may not recover expenditures on "political advertising" or "promotional advertising" from anyone but the shareholders.

It can be plainly seen in the above **paraphrasing** of sections 111 and 115 that the Federal standards are very general. Terms **such** as "cost-effective" and "**reliable**" are not detailed in their definition. The specifics of **ratemaking** and load management techniques are left up to the State regulatory authorities and the utilities to work out. This combination of **generality** and **delegation** of **power** to

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the State regulatory authorities leads to different interpretations of the law in different states.

Section 131 discusses the responsibilities of the Secretary of Energy. It states that the Secretary of Energy must periodically notify State regulatory authorities and utilities of-

- (1) load management techniques
- (2) developments and innovations in ratemaking techniques
- (3) methods for determining costs of services
- (4) any other data or information which the Secretary of Energy determines would assist in carrying out the purposes of this title.

Section 131 requires each utility to periodically gather information as FERC determines necessary to allow the determination of the costs associated with providing electric service.

The previous section has described all of the major points of Title I of PURPA. As was stated earlier, the regulations are very general and specifics are left up to the State regulatory **authorities** for the most part. For some regulations, FERC specifies the regulation (i.e. information gathered by utilities is determined by FERC).

### TI.3 Federal Authorities

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## II.8

Title II of PURPA is entitled "Certain Federal. Energy Regulatory Commission and Department of Energy Authorities". This section contains three main points: forcing **utilities** to connect cogenerating facilities to the power **grid**; requiring utilities to wheel power for cogenerators or for other utilities; and determining avoided cost. Unfortunately, many utilities are opposed to all three of these regulations.

Section 202 is entitled "**Interconnection**" and, as one might guess, it deals with connection of cogenerators to the power grid. It states that upon application of any electric utility, federal power marketing agency, qualifying cogenerator, or small power producer, FERC may **issue** an order requiring the physical connection of any cogeneration facility or small power producer.

A qualifying cogeneration facility is owned by a person not primarily engaged in the sale of power and one in which FERC determines meets certain requirements, such as minimum size, fuel use, and fuel efficiency.

This section essentially states that that if the cogeneration facility is judged "qualified" by FERC, the utility must connect it to the power grid.

Section 203 is entitled "Certain Wheeling Authority". Any electric utility or federal power marketing agency may apply to FERC for an order requiring another utility to provide transmission services to the applicant. FERC may

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issue an order if it finds the order is in the public interest and would

- (a) conserve a significant amount of energy
- (b) promote the efficient use of resources and facilities
- (c) improve the reliability of any electric utility system to which the order applies.

Section 210 is probably the part of PURPA which has caused the most controversy. The section is entitled "Cogeneration and Small Power Production". It states that **FERC** shall prescribe, and periodically revise, rules encouraging cogeneration and small power production which require electric utilities to offer to sell and purchase electric energy to (or from) qualifying cogenerators and qualifying small power producers.

This states that if a cogenerator is found to be "qualified" by FERC, a utility must provide an offer to buy or sell power with that cogenerator, regardless of whether the utility needs the extra generation or not. The rates for purchase by the electric utility are discussed later in the section.

The rates for such purchase or sale by utilities

- (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
  - (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.
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## II.10

The rate for purchase by utilities shall not exceed the incremental cost to the electric utility of alternative electric energy.

The term "incremental cost to the electric utility" means the cost to the electric utility of the **electric** energy which, but for the purchase from a **cogenerator** or **small** power producer, such a utility would generate or purchase from another source.

This concludes the description of this **section** of PURPA itself. Industry complaints, comments, suggestions, and **solutions** will be discussed in later sections.

### II.4 Other Subjects Covered in PURPA

PURPA also covers the regulations binding natural gas utilities. The purposes set forth are similar (i.e. conservation of energy, efficiency, equitable rates) to the **purposes** for electric utility regulations. PURPA also sets regulations related to advertising, termination of service, mandatory information gathering, and authorities of FERC and State regulatory authorities over natural gas utilities.

Title IV is entitled "Small Hydroelectric Power Projects". This section sets regulations for federal **funding** of small hydroelectric power projects that are found to be plausible and help to conserve energy. These regulations apply to new projects and to additions of generation to existing dams which currently have no

## II.11

generating facilities. The Secretary of Energy, in **conjunction** with FERC, is authorized to make loans of up to **90%** of the costs of such projects. The section also discusses loan rates and repayment plans.

Title V is entitled "Crude Oil Transportation Systems". It outline regulations, as one might guess, governing pipelines and other oil transportation systems.

### 11.5 Amendments to PURPA

Since its passage into law on November 9, 1978, PURPA has been amended four times. In **1980**, one small change was made in the regulation governing hydroelectric plants. In 1984, there was a change to one sentence within PURPA. In 1986, small changes were once again made to the section governing the liscensing of small hydroelectric projects. It entailed making provisions for saving protected rivers and wildlife reserves. The last amendment was made in 1990 and it was another simple change in wording. As one might tell from the previous discussion, PURPA remains essentially unchanged from its original form.

### 11.6 Complaints and Comments About PURPA

The regulation within PURPA that tends to cause the most controversy and misunderstanding is that utilities are forced to buy power from cogenerators if it can be bought

## II.12

for less than the "avoided cost" of the utility. Avoided cost is essentially the fuel cost and fixed costs **that** would be incurred on the utility to produce the same **amount** of generation. Most of the shortcomings of PURPA are traceable to the misunderstanding of these price signals [2].

Utilities have identified several problems **brought on by** the introduction of cogeneration and the idea of avoided cost.

(1) If a large number of consumers become cogenerators in order to reduce their power costs, this reduces the total **load** supplied by the utility. If this is not anticipated by the utility, the fixed costs of the utility are spread over a **smaller** number of customers and their rates increase [2].

(2) Avoided costs decrease as expensive peaking or intermediate generating facilities are replaced by cogeneration. The utilities avoided costs then become **cheaper than the** buyback rate for cogenerators. Since the **utilities** are often required to continue purchasing power **from** cogenerators due to long term contracts with them, the **utilities** have to pay more for cogenerated power than power **they** could produce themselves [2].

(3) There are many factors that effect avoided costs such as **time** of day, season of year, inflation, interest, etc. so that setting a firm buyback rate becomes nearly **impossible** in the long term.

(4) **Utilitie** are forced to buy power that they do not really need.

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(5) Since the utility is paying for cogenerated power at avoided cost, they are paying the cogenerator the same amount as if they had produced the power themselves. Therefore, no savings is passed on to the ratepayers.

(6) Since cogenerators are not as strictly regulated as electric utilities and their main business is not the production of power, the cogenerators may not provide as reliable a source of power as the utility would.

### 11.7 Solutions and Suggestions to Problems With PURPA

Several solutions have been suggested to the problems encountered by using the idea of avoided cost for determining the buyback rates from cogenerators.

(1) The use of short term contracts between utilities and cogenerators. These short term contracts are not effected that much by things such as inflation, interest rates, season of the year, or other long term variables.

(2) The substitution of formulae into contracts between utilities and cogenerators that adjust the buyback rate periodically as the factors effecting the rate change [3].

(3) The implementation of a bidding process where new levels of necessary generation are bidded on by cogenerators and utilities. Consideration would also be given to the performance and reliability of the planned facility. The

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generation would then be contracted to the lowest bidder with the best reliability [4].

(4) Another bidding process has also been suggested. In it, any utility, public power company, cogenerator, or independent power producer would be able to bid on the licenses to build and operate any new power plant, whether it be their own or someone else's. The contract would go to the lowest bidder with the best record of reliability, experience in building and operating power plants, and capital strength [4].

### 11.7 Conclusions

Since 1978, independent power producers have installed over 30,000 MW of capacity [5], but the full implementation of PURPA has a ways to go. In 1995, the average age of utility plants will be 25 years, up from 13 years in 1960. With utility planned installment of generation at a low level, the idea of promoting cogeneration becomes more and more important as time goes by. In order to bring the principles of energy conservation to fruition, the problems with avoided cost and utility opposition to cogenerators need to be alleviated. For further reading on the subjects of PURPA and cogeneration, references [6] - [8].

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## Chapter III - Demand Side Management in the Industrial Sector

### III -1 Introduction :

One of the primary objectives of a power company is to provide power as required by the customer **irrespective** of the time of need. In responding to this, the customer needs **are** satisfied but the cost of generating an additional unit varies from time to time depending on the situation. Hence, the power company always should aim to generate the next unit of power at the lowest possible cost. What we need to consider, in **analysing** this situation is the variability of the **load**. An index of load variability is **the** load factor which is the ratio of the average power delivered in a period to the peak power during that **period**. For economic operation, it turns out that the load factor should remain as high as possible for the utility to be economic in operation.

Prior to the late **70's** the electric utilities considered the demand as an exogenous quantity which was inherently uncontrollable. Statistical analysis provided the means to predict the growth of load and customer usage **patterns**. **However**, there was a consistent difference between the actual and the predicted demand and the load factors could not be improved as well as the planners thought they could. In fact, though the demand was consistently growing at the rate of 7% per annum till the energy crisis, during which it actually dropped to 3% making the planners calculations go haywire. Hence, it became obvious that better techniques had to be adopted to make the operations more efficient. It was at this stage that load management became a more serious concern than ever. Changing the load shape was the primary objective and techniques like Peak clipping, Valley **filling** and Load shifting were adopted.

These, however were activities that were adopted by the utility to improve its performance efficiency. Along with this emerged a much broader view, a more comprehensive approach to load management. This was referred to as DSM. DSM meant much more than load management and **came to** include all activities that were initiated to improve the load shape of the utility-including the aspect of marketing. It considered all aspects of load shape change, only, in this case, the demand was seen as the flexible controllable quantity and the idea that the utility could step up its generation to meet the demand was seen as a secondary issue.

From the customer point of view, DSM has many advantages **viz**, it reduces **cost**, gives more control over their electric costs, gives a choice in the type of service and also power security to the desired level. DSM, with alternatives such as cogeneration under

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## III -2

it's **umbrella** gives the customer **more** freedom to regulate his demand and it is here that DSM becomes a program in which customer participation **becomes** paramount. The type of customer also becomes **significant** in evaluating a DSM program, **because**, depending on the needs and the capacities of the customer, a DSM program can be made more or less comprehensive. For, aspects like power security and reliability needs may vary **widely** over a gamut of customers, **residential, commercial** or industrial..

This chapter will focus attention on the industrial sector and evaluate the options available as far as DSM in the industrial sector is **concerned**. **This treatment**, hopefully **will** serve to illustrate the concept of DSM as the planners **defined** it-i.e the planning and **implementation** of those utility activities designed to influence customer use of electricity for effecting the desirous changes in the load shape.

### III -2 DSM alternatives :

This section considers the available options in DSM to effect its **efficient** implementation. In further discussions, we will discuss the relevance of each of the options in the industrial sector, considering each of the **alternatives** in due **turn**. The alternatives are listed below:

- a] End use equipment control
- b] Utility equipment control
- c] Energy storage
- d] Incentive** rates
- e] Dispersed** generation
- f] **Energy** co-ops
- g] Customer DSM promotions
- h] Performance improvement -equipment and systems

We **will** now examine the ramifications and alternatives **proffered** by these alternatives listed **above**

#### a] **End use equipment control** :

This has turned out to be one of the **most** active areas of DSM technology development. However, the majority of the work in this area is residential and commercial and industrial alternatives are just beginning; to attract attention in this **area**. **However, as** the term implies, this alternative gives **control** of the equipment at the **user's** end to the **utility**. **One** example is that of **airconditioners** in **residences** that may be switched off for a certain amount of time by the utility for adjusting it's demand

### III -3

curve. However, this option would not be eminently suitable for industry since the industry requirements are not so easily met. Labour problems enter into the picture and combined with actual process requirements, this can prove to be ineffectual or impossible. However, a few utilities have targeted the industrial sectors for their initial DSM programs and typically, since industrial sectors have high load factors, these alternatives are used to purposely perturb the load shape to compensate for the poor residential load factors. As far as chiller plants in industry are concerned, the duty cycle is reduced by a subscribed amount during a designated peak period during the day.

Apart from these, usually DSM programs also allow for more comprehensive schemes for reducing load peaks through the use of equipment interlock **devices**. This usually stems from the use of energy management systems (EMS) that prevent the demand from going up beyond a point. Usually, the EMS detects an increase and sends out a signal to a relay part of an equipment interlock **circuit**. **Selected** loads are then tripped off according to the logic in the circuit. This has been adopted in practice by industrial units quite regularly.

#### b) Utility equipment control :

This option includes the alternatives of voltage **reduction**, **feeder** control and power factor control. However, variations in pf or voltage levels are adopted in industrial units due to the fact that even if the voltage levels are reduced from the utility point of view, the industry supply is taken from a transformer at the input which has variable taps. The voltage level to the equipment **therefore**, can be controlled internally in an industrial complex. However, this may not be true for pf control and it still remains a controversial issue. Feeder control also is not viewed as a normal measure and formalised procedures for regulatory feeder controls need to be developed.

#### c) Energy Storage :

This was one of the first techniques to be identified for load management. Traditional ideas have included heat and cold storage techniques and, in this area, due to their bulk capacity, industrial systems have proven to be extremely cost effective. Large amounts of savings are possible through demand charges and TOD rates. Installation costs in this type of work are extremely site specific. Other techniques of energy storage such as heat storage etc **haven't** been able to effect great changes in the industrial sector to large extents.

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d] Incentive rates :

This **forms** probably the most important alternative in DSM . Incentive rates can be applied as a DSM alternative within themselves or as an incentive to drive the economics and the motivation to the succesful implementation of other types of DSM alternatives. Since the birth of DSM, many innovative rate designs have been **developed**. Popular among these schemes are time differentiated rates, spot pricing, **demand** rebates etc. In the industrial sector, common alternatives include shifting the production schedule to uniformise the demand and make use of **reduced** rates during that period. However, these arae not the only available options. As far the industrial sector is concerned, many other options make themselves viable. The use of energy efficient devices make the utilisation of energy less and have the effect of reducing the demand. There are many such options available in industry, for **example** the soft-start starter;; for induction motors of large capacity as used in air compressors etc. In addition there **are** energy efficient air conditioners which are more common in the residential sector, but nevertheless have been used quite often in the industrial sector.

e] Dispersed generation :

This is a load management alternative that comes in many forms. Alternatives such as solar cells, standby generators, cogeneration, small hydro, and **similar** types of independent generating units can be **coordinated** by the utilities to adjust **the** demand and distribute it evenly. In some cases, these **were** installed by customers or third parties in direct competition with the utilities. **Howevet**, in the industrial sector, there are a wide variety of options available in this area, depending on the size and type of the industry. In plants which generate lot of waste product with comparable heat content, auxilliary power plants can be set up internally in the company to internally generate power to meet some of the demand if not all of it. In **the** event of failure of power, industries usually have independent generation sources **that** can take care of the industry demands for a short amount of **time**.**However**, this arrangement would involve discussions on power security, and aspect which varies from customer to customer, especially in the industry- for example in a high **precision** ceramic industry power **failures** in the middle of a process would probably lead to **damage** in the product since **the** heat cycle may have been interrupted. Other alternatives like wind generation etc **have** been tried but purely on an experimental basis and not on a **full** scale.

f] Energy coops :

This alternative is also considered one of the available alternatives in DSM. **The** concept of energy coop implies the linking of two or more energy sources or

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generating sources to share the demand in an equitable fashion. This way, excess demand in one unit is compensated for by shifting the load to the other and vice versa. This ensures a better load factor for both the utilities.

#### g] Customer **DSM** promotions :

It was mentioned earlier that **DSM** per se constituted not only the act done by the utilities to alter the shape of the load curve but also the allied planning and management operations involved. One of these activities is the customer promotion but this does not have much relevance in the industrial sector. In the case of a residential or commercial area, the promotional campaign by a group of residents would probably convince another group of residents to pursue DSM options- however, in the industrial sector it's a different story. Usually the industry adopts some DSM options primarily to reduce energy consumption and increase profits. Due to the competitive nature of an industry, any relevance to an increased margin in profits would probably appeal to the industrial consumer much more easily. Hence promotional activity is probably not targeted towards this sector as much as it is towards the residential sector.

#### h] Performance improvement equipment and systems :

A brief glimpse into this alternative was given while discussing about the ideas i incentive rates. The use of performance improvement equipment is not uncommon in industry and any device which aims to reduce energy substantially would be immediately installed by the industry. An example is the soft start energy saver starter for heavy duty induction motors for typical applications such as in air compressors. These devices serve to reduce the peak during sudden loads such as starting . A category of equipment that has been used in this is usually referred to as high EER equipment, or high energy efficiency ratio equipment. Typical examples are high EER airconditioners which cool with lesser energy consumption than other airconditioners. Most devices of this class are household appliances that find use mostly in the residential and commercial sector.

### III -3 Evaluation of **DSM** programs :

So far the options available in DSM were considered. These options have been applied with a measure of success and a logical step would be

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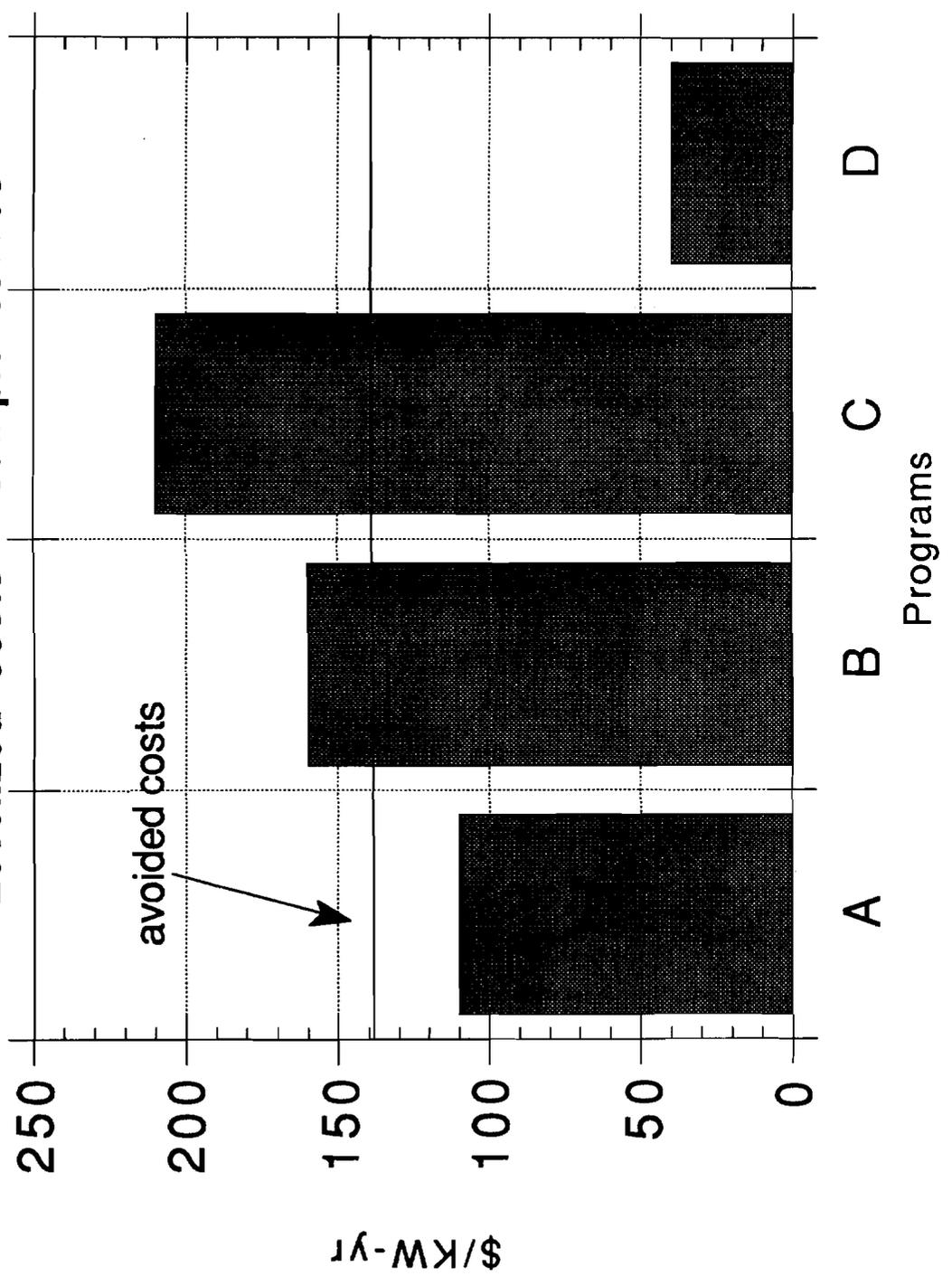
to evaluate these **DSM** programs based on their end objectives. In such a program the end **objective** is usually cost effectiveness and though specific cost effectiveness is defined by each utility, it is usually balanced against the utility's **avoided** cost. **PURPA** defines the avoided cost as the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying **facility** or facilities, such utilities would generate itself or purchase from another **source**. In analysing the cost effectiveness of a **DSM** program, the following variables are **considered**. They are listed as follows:

- a] Avoided capacity costs
- b] Kilowatt reduction -at system peak hour, on a per customer basis
- c] Equipment, installation, removal, operation and maintenance costs
- d] Financial costs like cost of money, escalation rates etc
- e] Generation factors
- f] Incentives
- g] **Worth** of the project
- h] **Levelized** costs in \$/kw-year
- g] **Benefut/cost** ratio

All these variables are considered periodically in evaluating the: worth of a **DSM** program. The chart given in Fig 1 shows the levelized costs of **individual** programs. The analysis of this, however, is much more complicated in the case of an industry where a whole lot of other factors have to be taken into account.. **Computing** the benefit /cost ratio and other factors are done after including direct and indirect effects of the **DSM** programs, which go beyond just reduction of demand and energy.

Usually different levels of evaluation are adopted and this not **only** restricts itself to comparison of alternatives, but also incorporates a projection of **costs** and forecasting the effects of the various combinations that have been proposed in **the DSM** plan. In a large industrial belt, market surveys can be conducted and a sample cost effectiveness **estimate** can be obtained. Also, this survey would possibly reveal some of the free riders, people who particiapte in **DSM** programs and add to the existing costs. Customer use patterns can also be found .All these activities can be utilised in **the** ultimate step of **DSM** i.e . Generation planning, which helps us to evaluate the **desierd** supply side generation **mix**.

**Levelized costs : Sample curves**



**III -4 Conclusion :**

An analysis of DSM options in the industrial sector has been done and the various options that are available to industrial users are considered. It turns out that **the** DSM alternatives that are considered can be used to evaluate supply side options like hourly load reduction, hardware costs etc. Cost effectiveness and benefits are paramount in this sector and the **DSM alternative** to be adopted varies from utility to utility., specifically in a predominantly industrial area, depending on the alternatives available at the industrial consumer's end.

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Chapter IV  
Demand-Side Management  
for the  
Residential and Commercial Sectors

Kevin G. Karagory

IV.1 Introduction

With the passage of the Public Utility Regulatory Policies Act (**PURPA**) in 1978, state regulatory authorities were required to make a determination about implementing demand-side management programs. As a result of the preceding possibility of state mandated demand-side management programs and an every increasing concern related to the deregulation and the environmental consequences of electricity production, electric utilities have increasingly focused on demand-side management programs.

The primary purpose of demand-side management is to allow the electric utility to directly influence the customer demand for electric power in a predetermined way. This results in affecting the load curve by increasing or decreasing the use of electricity or by shifting use from one time period to another.

This activity leads to improved efficiency in the use of energy and capital resources. Thus allowing the electric utility to enhance economic productivity and reduce power plant emission of pollutants.

The rest of this paper deals with the various **demand-**side management options currently available to the electric utility. Residential and commercial sectors have been grouped together because the demand-side management options

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## IV.2

available to each are quite similar. Only in the weighting of a particular demand-side management option do they differ. Lastly, the crucial topic of customer **acceptance** and participation is discussed.

### IV.2 Demand-side management options

The rapid growth and advancements in the field of electronics has subsequentially given rise to a wide variety of demand-side management options available to the electric utility. These options can be grouped according to methodology.

The first demand-side option discussed is the direct control of the end-use load. The most common of these programs is the control of water heating. Water heaters can be equipped with dual-element time clock controllers which provide off-peak water heating. Other methodologies can be implemented to provide direct control over the water heater. **These** methods include radio signals or control **signals** sent directly over the electric lines. Common **implementations** of this program call for water heating stoppage of between 2 to 3 hours with stoppage of up to 6 hours not uncommon depending on the peak loading conditions.

Another of these selective power denial programs is the direct control of the air conditioner. This can provide the largest drop during peak loading for the residential sector. Typical outages for the air conditioners are 10 **minutes on/20** minutes off. Direct control of pool motors is another example of selective power denial.

Energy efficiency programs make up another large demand-side management option. This includes not only more energy efficient appliances but also improved structural insulation.

Energy efficient lighting replacement makes up the greatest savings of any commercial demand-side management option. Energy reductions of up to one half can presently be had with today's technologies. Illumination accounts for one quarter of the electricity sold in the U.S. Many people believe that lighting systems may have the largest potential for energy savings of any electric load.

Other energy efficiency programs include high efficiency refrigerators, air conditioners, and water heaters. Water-saving showerheads, water-heater wraps, pipe insulation, and water temperature adjustments are considered easy savers in this area.

The third demand-side management program discussed is that of conversion. This includes the conversion of an electric appliance to some other form of energy. The most common of these is the replacement of an electric air conditioner with **gas/steam** driven air conditioner. This can be implemented in the commercial sector.

Also included in this category is the replacement of one type of electric appliance by another type of electric equipment. An example of this is the replacement of an electric furnace with that of an energy efficient heat pump.

The last of the demand-side management options is that of variable rates. This includes both time-of-day and time-of-use rates. Time-of-use rates also take into consideration the day of the week and the time of the year.

The effect of the variable rates is to shift the load demand to an off-peak time using the pressure of more costly rates during the peak load times. Typical increases in peak electric rates range anywhere from 1.5 to 4 times the off-peak electric rate. This results in the customer "voluntarily" curtailing electricity use during peak load conditions.

Thus there are many demand-side management programs for

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#### IV.4

the electric utility to consider. Allowing the electric utility to tailor the options to better serve their needs.

#### IV.3 Customer acceptance/participation

A major consideration of the implementation of any demand-side management program is that of customer acceptance and participation. Although there is a willingness in the consumer to participate in order to avoid high energy cost or to save money, acceptance can only occur if the customer is kept fully aware of all aspects of the program.

A trial period is required to gain and keep the consumers trust in the overall goals of the demand-side management program. Without the consumers **willingness** to participate the goals of the program can never be fully reached, or may fail altogether.

#### IV.4 Conclusion

Demand-side management programs are clearly an economic and marketing problem, and not an engineering one. The technology to implement these programs have existed for some number of years now. The financial and energy savings to be gained by such programs are clear. Demand-side management is not the cure-for-all for the electric utility industry. **It** does, however, provide an easy resource for modest savings for the utility and the consumer.

There are clear gains to be made with demand-side management and they should be exploited. This author firmly believes that the major gains economically will **not** come from demand-side management less energy-efficiency programs, **but** will in fact come from the area of energy storage. Thus, this author's attention in the future **will** focus on

the area of advanced electric energy storage.

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## Chapter V High Voltage Direct Current Power Transmission

With the passing of the **PURPA**<sup>[1]</sup> act in 1978, electric utilities were placed on a path of conserving energy in many new ways. As stated in Title I of the act, the purposes of the **PWRPA** act are to encourage (1) conservation of energy supplied by utilities; (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and (3) equitable rates to electric consumers. Among the many methods being implemented to meet these goals is the use of high voltage direct current (HVDC) power transmission systems. This chapter will attempt to provide an overview of HVDC, its advantages and disadvantages, applications to load **flow** control and some of the technologies which make HVDC possible.

### V.1 Introduction

The use of HVDC dates back to the earliest days of power transmission. From 1889, R. Thury designed dc transmission systems using series wound dc generators. Near the turn of the century, he had installed a system between Moutiers and Lyons in Europe which had a capacity of 20 MW over a distance of 138 miles, 23 of which were composed of cables, at a voltage of 125 **kV**<sup>[2, 3]</sup>. The system was of the constant current type and was used as reinforcement of an existing ac system. In Thury's own words, "The two systems shake hands fraternally in order to give each other help and assistance."

The method of commutation in Thury's system was purely mechanical which was no problem for the low speed water driven turbines of the day. However, with the advent of high speed steam turbines, the mechanical commutation became too difficult to manage. Subsequent transmission systems were almost exclusively of the ac type. Only with the successful development of mercury-arc valves did HVDC begin to recapture attention. Now, with the advent of reliable solid state devices to replace mercury-arc valves, **HVDC's** appeal is growing quickly.

Although the cost of **ac-dc** and dc-ac conversion is expensive, the advantages of power flow control, reduced losses and greater capacity (all to be discussed shortly) make HVDC a worthwhile transmission scheme. With the continuous advances in semiconductor devices, the conversion process will become cheaper and more efficient, thus making HVDC ever more cost effective. HVDC is an established fact which is the motivation for this chapter.

## V.2 General AC and DC System Considerations

Electrical power may be transmitted by means of underground cables or **overhead** lines and the relative merits of ac and dc transmission should be **compared** for each case. The differences between ac and dc **transmission** are primarily economic but also include performance and environmental factors. This section is intended to give a reasonable foundation on which to evaluate the relative qualities of ac and dc transmission.

Let's first consider the economics of converting a 3-phase double circuit ac **system** to a dc system. The dc system will then have three circuits with each having two conductors at plus and minus  $V_d/2$  with respect to **earth**. On the basis of the same percentage line losses and the same insulation level:

$E_p = \text{ac phase voltage}$ ,  $I_L = \text{ac line current}$ ,  $I_d = \text{dc line current}$ .

For **the** same insulation level,  $V_d/2 = (2)^{1/2}E_p$

For equal percentage losses,  $\frac{\text{ac losses}}{\text{ac power}} = \frac{\text{dc losses}}{\text{dc power}}$

$$\frac{6I_L^2R}{6E_pI_L} = \frac{6I_d^2R}{3V_dI_d} = \frac{6I_d^2R}{6(2)^{1/2}E_pI_d}$$

Therefore,  $I_d = (2)^{1/2}I_L$  and,  $\frac{\text{dc power}}{\text{ac power}} = \frac{6(2)^{1/2}E_p(2)^{1/2}I_L}{6E_pI_L} = 2$

Thus, without making any modifications to the existing transmission lines, twice as much power (or more if the power factor of the ac line is below unity) can be **delivered** using dc rather than ac with the same percentage **losses**<sup>[3]</sup>. This is an **important** consideration given the increasing difficulty in gaining right of way and the cost of constructing new overhead transmission lines. In many cases, finding suitable corridors for new overhead lines is simply impossible. **This** is forcing many utilities to upgrade existing right of ways which is still far cheaper than going to underground **cable**<sup>[4]</sup>.

A recent study<sup>[4]</sup> has found that power along existing HVAC lines can be increased by as much as 3.5 times or more. This is done by making changes to the tower head, insulator assemblies and conductor configuration but with no changes to the conductors, tower bodies, foundations and

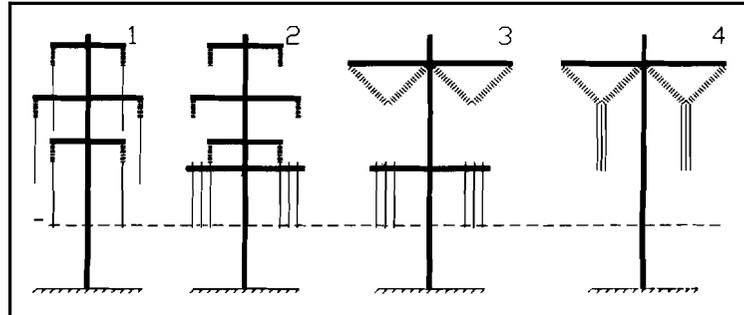


Figure V.1 Steps for converting existing double 3-phase ac to triple circuit dc.

without adding intermediate towers. Since no change is made to the conductors, the total rated current remains the same, which means that the power increases proportionally to the adopted new dc line to ground voltage. Figure V.1 shows the steps suggested for converting an existing double circuit 3-phase ac transmission line to a triple circuit dc line. First, the existing tower is fitted with a provisional **crossarm** for temporary holding of the six lines. Then the existing crossarms are removed and replaced with a single larger **crossarm** which holds all six lines. Note that the final tower has larger insulators and higher ground clearance to support much higher dc voltages. An in-depth study of the conversion process is given in [4].

Along with the advantage of large power flow, the conversion of ac lines to dc also provides a reliability improvement. For one, three dc circuits are inherently more reliable than only two ac circuits. If one dc circuit goes down, 66% capacity still remains in the dc case whereas for ac, only half remains. Secondly, if a single dc conductor goes down, the earth can be used as a temporary return for the dc circuit thus leaving five conductors active. If one conductor fails, the dc system only loses 17% capacity but the ac system loses 50%.

Stability is also improved in a dc system. It is well known that the stability of an ac line is dependent on the power per circuit and the length of the line. For long lines, stabilizing equipment such as series capacitors, shunt inductors or even intermediate switch stations may be needed thus increasing the cost of the ac system. This problem is non-existent in dc systems.

HVDC systems are also immune to the skin effect. This provides more uniform current distribution and better utilization of the metal in dc systems.

## V. 4

In the case of underground cables, dc is far better than ac. This is primarily due to the large capacitance of underground lines. In broad terms, the effective power transmitted per cable by dc is about 2.5 times that by ac<sup>[3]</sup>.

The primary disadvantage to HVDC is the higher cost of the substation which is about two or three times the cost of an ac counterpart. However, recent studies have shown that HVDC becomes more economical than ac at a transmission distance of several hundred miles for overhead lines and only twenty miles for underground cable systems". Also, given the rapid advances in semiconductor technology, the cost of dc substations will get ever closer to the cost of ac stations.

There are also other problems with HVDC. First, there is no easy way to transform dc voltage as there is with ac. For this reason, ac is far more appropriate for distribution. Also, HVDC converter stations consume reactive power which must be supplied from the ac side. The steady state reactive power requirements of the converter may be 40 to 50 percent of the real power and in the case of transients as much as 75 percent may be needed.

One last disadvantage of dc is difficulty of switching. With ac, the current automatically comes to zero every half cycle which makes switching easy. In dc systems, no current zero exists and all the energy stored in the system has to be dissipated before interruption can be obtained by circuit breakers. In other words, since the current in the ac system goes zero, any contact arc-over is automatically extinguished. Without a current zero, the arc-over in dc switch gear is a difficult problem to solve.

### V.3 The Commutation Process

The conversion of power from ac to dc and from dc to ac is the central process of HVDC transmission<sup>[2]</sup>. This section is provided to give a clear understanding of conversion basics. Figure V.2 shows a circuit which passively converts 3-phase ac to dc current. The inductors on the dc side serve to smooth the dc current and we therefore assume that the dc current is constant. In such case, the diodes switch each ac phase onto the dc lines in sequence so that the positive terminal is always

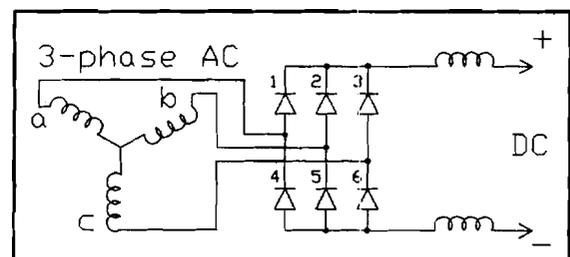


Figure V.2 Commutation circuit.

connected to the most positive ac phase and the negative terminal is always connected to the most negative ac phase. Figure V.3 shows the ac voltages in dotted lines and the dc voltages in solid lines as produced by the circuit of Figure V.2. The individual phases are labeled (a,b,c) and the diodes which are conducting at given times are labeled in parenthesis. For example, when phase "a" is most positive, diode 1 is conducting and the positive

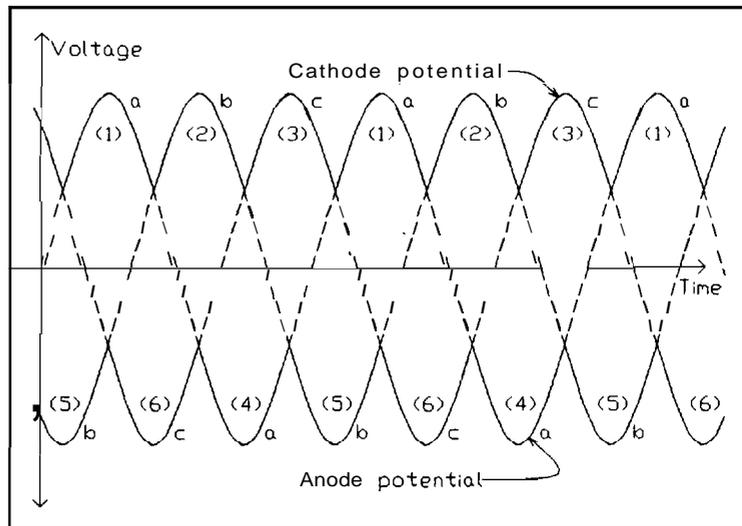


Figure V.3 Voltage wave-forms of the basic ac to dc commutation circuit.

dc terminal follows the phase "a" voltage. Then, when phase "a" crosses phase "b" (phase "b" goes more positive than phase "a"), the current is commuted over to diode 2 and the positive dc terminal voltage follows the phase "b" voltage. Note that this situation provides no control of power flow or dc current level due to the passive nature of the diodes. The diodes always connect the most positive and most negative ac phases to the dc positive and negative terminals, respectively, and power flow is determined solely by the load impedance on the dc side.

Of course, power flow control is one of the primary advantages of HVDC transmission. In fact, it is necessary! HVDC transmission is used to send power from one ac system to another ac system which means dc power must be converted to ac power at the receiving end. The circuit of Figure V.2 can only convert ac to dc. As we will now see, a very simple modification to that circuit provides us the means to convert dc to ac and also to precisely control the amount of power transferred from one end to the other.

In order to control the power flow in the dc lines we must delay the commutation of current by some firing angle,  $\alpha$ . In other words, we do not switch to the more positive (or negative) ac phase immediately. The effect of such a delay is shown in Figure V.4. The small delay essentially lowers the magnitude of the average dc voltage which lowers the power transfer. This delay can be obtained by replacing the diodes in our original commutation circuit with a silicon controlled rectifier or SCR. The SCR, described in detail in section V.4, provides the means to precisely determine the firing angle of the converter.

## V. 6

Once the delay is increased to  $30^\circ$ , the positive dc voltage begins to have negative peaks and the negative dc voltage will have positive peaks. This is no problem because the **smoothing** inductors keep a **constant** current flowing. The **average** dc voltage is what's important. However, once the firing **delay** reaches  $90^\circ$  the average dc voltage is zero and **power** flow in turn goes to zero. Figure V.5 shows the  $90^\circ$  delay case. Now here's the good part. For firing delays between  $90^\circ$  and  $180^\circ$ , power is transferred from the dc to the ac system. The delay angle of  $180^\circ$  is the **point** of "full inversion" or maximum power transfer from the dc line to the ac system. One small catch is that the SCRs have to be **physically "flipped"** to achieve power flow reversal.

This is because the SCRs, like diodes, can only pass current in one direction. Therefore, to reverse power flow and, **hence**, current direction, the SCRs must be reversed. This is no big problem since HVDC is used mainly to transfer power from some remote generating station to the ac system and the power flow need not be reversed but only controlled.

Figure V.6 shows the circuit scheme used to transmit HVDC power from left to right. The ac voltage at the left is converted into dc for transmission. The converter on the left then converts the dc back to ac for distribution. Note that the SCRs in the receiver are reversed in polarity as compared to the SCRs in the

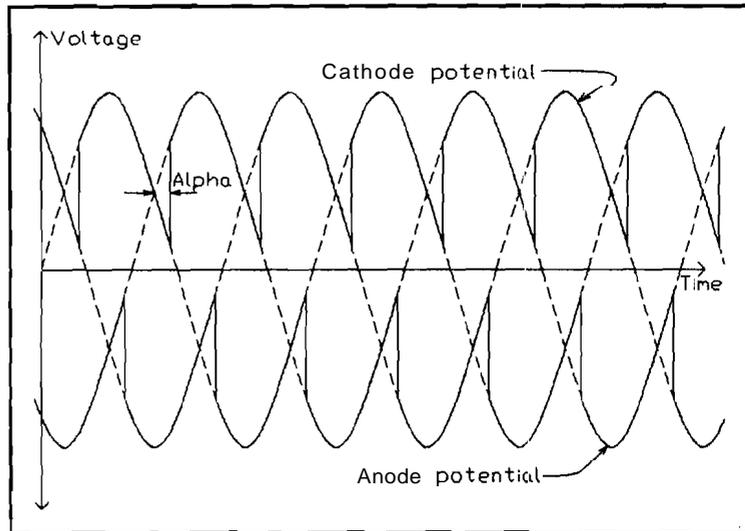


Figure V.4 Effect of valve firing delay on the dc voltage.

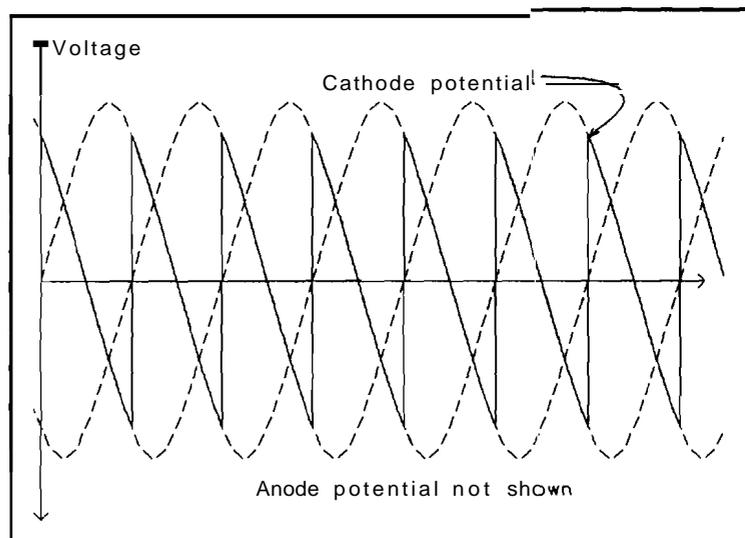
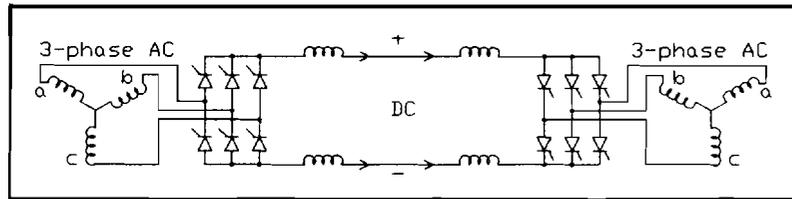


Figure V.5 Positive dc voltage at a firing angle of  $90^\circ$ .

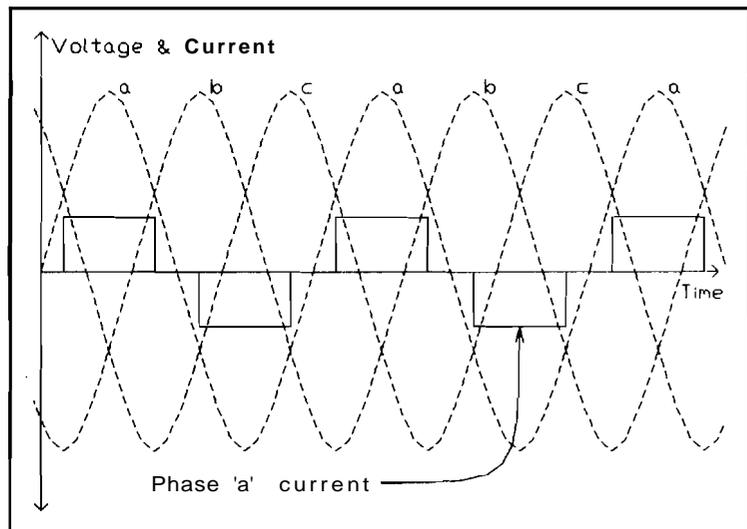
transmitter. Current flow is always from left to right in this situation. To transfer power, the firing angle in the transmitter is set somewhere between  $0^\circ$  and  $90^\circ$  and the angle at the receiver is set between



**Figure V.6** Circuits at transmitting (left) and receiving (right) HVDC stations.

$90^\circ$  and  $180^\circ$ . Power can be transferred with complete control regardless of the conditions in either ac system. Also, the transmitter and receiver must be in agreement as to how much power is to be transferred or the system will not work. Therefore, some method of communication must be maintained between the two stations to keep things running smooth. This can be done via microwave, dedicated phone lines or RF transmission of data directly over the HVDC lines.

Along with the fantastic advantage of power flow control, HVDC converters have some problems which must be dealt with. One such problem is that of harmonics. Since the dc current is held constant, the current transferred to and from each ac side is also constant, albeit switching from phase to phase. Figure V.7 shows that the current on each ac phase is a square wave which we all know is full of harmonics.



**Figure V.7** Phase current for ac to dc conversion.

The use of tuned filters on the ac side is the primary method of harmonic elimination in practice today. Alternate methods of harmonic control are magnetic flux compensation, harmonic injection and dc ripple reinjection. For a description of these methods please see [2].

Another problem of the dc conversion process is illustrated in Figure V.8. In this case the firing angle is  $60^\circ$  and the figure plainly shows that the current in phase "a" is lagging the voltage. The converter is therefore consuming reactive power (**VARs**). Likewise, an inverter will also consume reactive power. The real

## V. 8

problem is that the amount of **reactive** power consumed varies with firing angle. Hence, the amount of capacitive compensation on the ac sides must be adjusted along **with** the firing angle. This problem is solved by **switching** capacitors in and out of **the** system as needed. [3] **provides** a detailed description of reactive power considerations. Reactive power regulation and other system dynamics are also covered in [6].

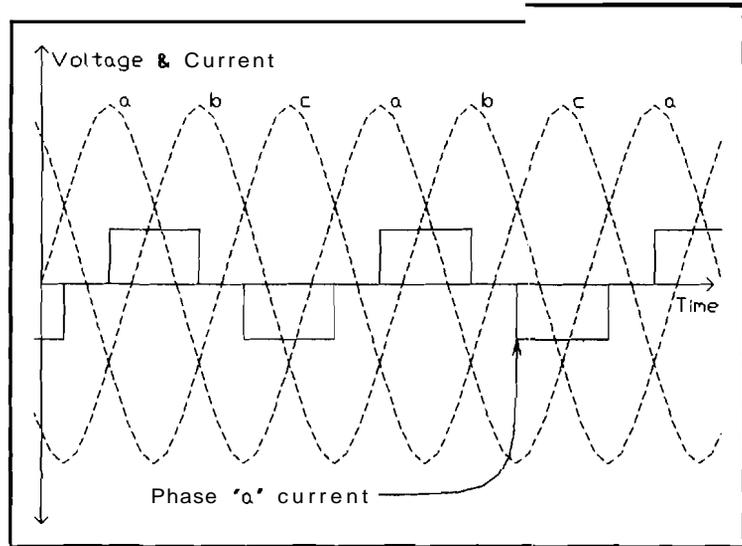


Figure V.8 Phase current when the **firing** angle is  $60^\circ$ .

One last problem of HVDC converters is that of radio frequency electromagnetic noise generated during valve firing<sup>tn</sup>. This noise can affect the **performance** of adjacent communication, control and **computer** equipment. Therefore, it is important to measure, predict and mitigate the interference.

In the situations thus far described, the dc transmission is of the constant current type and this is currently the method used in practice. Recently, however, advances have been made in thyristors that can be turned off by the application of a turn-off gate voltage. These new devices are called gate turn off **SCRs** or **GTOs** (see section V.4). Such devices allow the use of pulse width modulation (PWM) converters which can transmit HVDC power at constant voltage **instead** of constant **current**<sup>[8]</sup>. The main advantages of such a system are that multiple connections to the dc lines can be easily accommodated and bidirectional power flow can be accomplished at any station. For further information on this, the reader is referred to [8] and [9].

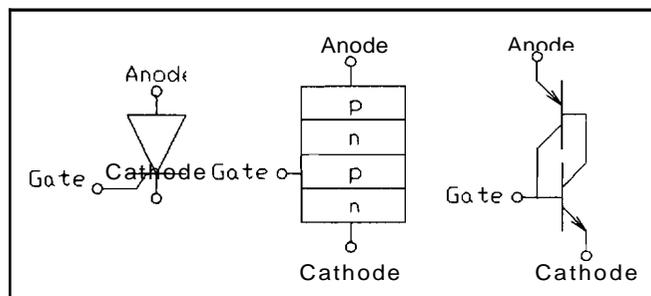
The concepts presented in this section are fairly simple but provide power flow control not attainable with pure ac systems. Power flow can be controlled in different patterns than Kirchoff's current law would dictate for an **all** ac network. The reader should also note that the real commutation process is somewhat more complex than that described here. For example, ac side inductances lengthen the **commutating** time. In other words, the current doesn't switch from one thyristor

to the next instantly but the two will both conduct for some finite commutation time. The effect of this is that the dc line voltage will be an average of the two ac phase voltages connected during the finite commutation time. An excellent treatment of this topic and many others on HVDC can be found in **Arrillaga**<sup>[2]</sup> and **Adamson**<sup>[3]</sup>.

#### V.4 Semi-conductor devices in HVDC

In order to make use of HVDC transmission, three phase **a.c.** voltages need to be commutated or "switched" in and out of the **d.c.** circuit. Although this switching has been done successfully in the past using mercury-arc valves, the advent of the thyristor, specifically the silicon controlled rectifier (SCR), has made HVDC a truly practical and economic method of power transmission and load flow control. In comparison to the mercury-arc valve, the SCR is cheaper, smaller, more reliable and eliminates the arc-back problem of mercury-arc **valves**<sup>[2]</sup>.

As shown in Figure V.9, the SCR is a four layer semiconductor device with three p-n junctions. The contact to the outer p-layer is the anode and that to the outer n-layer is the cathode. Also shown in Figure V.9 is an equivalent circuit consisting of **pn** and **npn** transistors connected together such that they form the pnpn structure. This equivalent circuit is very useful in understanding how the SCR functions.



**Figure V.9** SCR symbol, structure and circuit.

The I-V characteristic for the SCR is now shown in Figure V.10. As one might expect, the SCR has a very similar reverse bias curve to that of a regular diode. Under reverse bias, the two outer p-n junctions are reverse biased and little current flows through the device until the reverse breakdown voltage ( $V_{BR}$ ) is reached. The typical reverse breakdown voltage for modern **SCRs** is about 5000 volts. Note that surpassing this voltage will usually be destructive.

Forward bias is where the SCR shows its true colors. Without any gate current applied, the SCR will still not conduct when forward biased because the center p-n junction is reverse biased. Now, take a look at the equivalent circuit

## V. 10

for the **SCR**. If a small current is applied to the gate (the base of the npn transistor), transistor action will collect current across the center junction. A collector current equal to  $\beta_{npn} \cdot I_{gate}$  flows through the npn transistor ( $\beta$  is the current gain). Notice in the circuit that this current is coupled to the base of the pnp transistor and therefore serves to turn it on as well. The pnp transistor's collector current is now equal to  $\beta_{pnp} \cdot \beta_{npn} \cdot I_{gate}$ . This current is, in turn, coupled back to the gate. Therefore, our initial gate current is multiplied by the two transistors and is reapplied to the gate. Such positive feedback quickly saturates the transistors at which point the **SCR** looks like a forward biased diode to the external circuit. Keep in mind that the initial gate current need not be continued once the device is turned on because the **SCR** is self latching due to the regenerative nature of the transistor circuit.

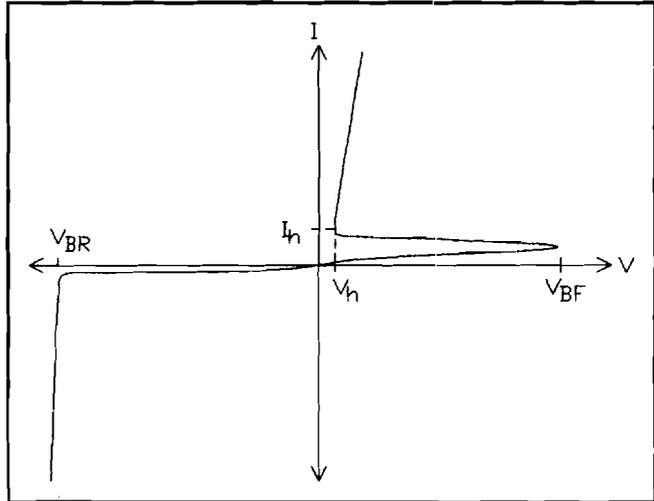


Figure V.10 SCR I-V characteristic.

**Notice**, on the I-V curve, that the **SCR** can turn itself on at high enough forward voltages ( $V_{BF}$ ). This is caused by avalanche breakdown of the center p-n junction. The avalanche current looks just like gate current to the **SCR** and it, therefore, turns on. The device can also be turned on by rapidly varying voltages applied to the anode well below the forward break-over voltage. This is caused by capacitive coupling of displacement currents to the gate and is called the  $dV/dt$  effect. Neither of these turn-on mechanisms is generally desirable and care must be taken to avoid such situations in **HVDC** circuits. Protection against avalanche turn on is usually handled by a zinc-oxide varistor<sup>[10]</sup> in parallel with the **SCR**. The varistor is simply a device that has high resistance until a large voltage is placed across it. At high voltage, the varistor looks like a short circuit and thus shunts any voltage peaks which might otherwise turn the **SCR** on. The  $dV/dt$  effect is thwarted by a circuit called a "snubber" which is basically a capacitor in parallel with the **SCR** to shunt very high frequency voltage swings.

Another method of turning on the **SCR** is by way of light. Photo-generation of minority carriers in the depletion region of the device can be used to supply the initial current for amplification by the transistor effect. I mention this because

## V. 11

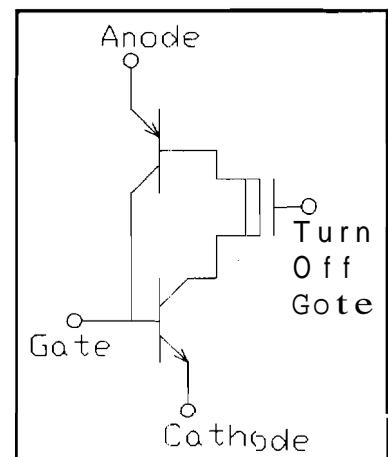
recently developed HVDC valves using light triggered SCRs have shown improved reliability, noise immunity and flexibility over electrically triggered units<sup>[11]</sup>. In actual application, the light is used to trigger small SCRs which in turn trigger the large valving SCRs.

You may be wondering, "How do we shut the SCR off?" The positive feedback nature of the SCR keeps it on after the initial gate current is removed. Again referring to the I-V curve, if the current through the SCR falls below a minimum holding current,  $I_h$ , the transistor action will cease and the device shuts off. Thus, the only way to turn off a conventional SCR is to bring the current below  $I_h$ . In practice, this is done simply by taking the SCR into reverse bias and, as will be discussed next, other methods of turning off an SCR are being developed. A very detailed analysis of the SCR can be found in **Sze**<sup>[12]</sup> for those who wish to delve deeper.

Recently, a device derived from the SCR has begun to show great promise in HVDC applications. This device is called the gate turn-off thyristor (**GTO**)<sup>[13]</sup>. As can be seen in Figure V.11, the GTO is almost the same as the SCR except for the depletion mode mosfet. In fact, if the turn off gate is left open circuited, the device functions identically to an SCR. However, the application of a negative bias to the turn off gate cuts off the feedback path to the base of the pnp transistor and thus shuts the thyristor off. Such a device allows not only the control of firing angle but also the pulse width during which time the SCR is conducting. Such flexibility has the potential for fantastic control of power flow in HVDC systems.

Devices capable of controlling as much as 1000 amps/cm<sup>2</sup> have been reported. Unfortunately, the greater complexity of the device currently limits the blocking voltage to little more than 500 volts<sup>[13]</sup>. This limitation is not a major problem however because the GTO can be placed in series with standard SCRs. In such a situation, the normal SCRs would do the dc blocking and the lone GTO can shut off the current to the whole string of thyristors.

With the modern trend in solid-state devices being to shrink devices down to nearly atomic dimensions, it is fascinating to see the exact opposite trend applied to high power SCRs. With wafers today holding literally tens of millions of



**Figure V.11** GTO-SCR equivalent circuit.

transistors, the modern SCR is a true stand-out being a single device covering an entire 100mm diameter wafer<sup>[14]</sup>. That's a 60 cm<sup>2</sup> solid-state device! This huge device is sandwiched between two metal heat sinks each having high velocity water cooling ducts running through them. In the future, device sizes will grow and two-phase freon cooling systems will be employed<sup>[15]</sup>. Current devices with an efficient cooling system are capable of carrying a whopping 4000 amps! Thus, recently designed HVDC convertors have no need for parallel devices. Of course, they must be placed in a series chain to handle high voltages since they currently only withstand about 5000 volts.

One last semi-conductor device completely unrelated to the SCR is worth mention. This is the photoconductive circuit element, or PCE, which consists basically of semi-insulating (undoped) silicon<sup>[15]</sup>. This insulating, nonconductive silicon can be made highly conductive by applying laser or other optical excitation having photon energy exceeding the band gap energy ( $\approx 1.1\text{eV}$  for silicon).

Electron-hole pairs are created by the impinging photons thus making a highly conductive layer at the surface of the silicon. Figure V.12 shows the basic PCE device geometry.

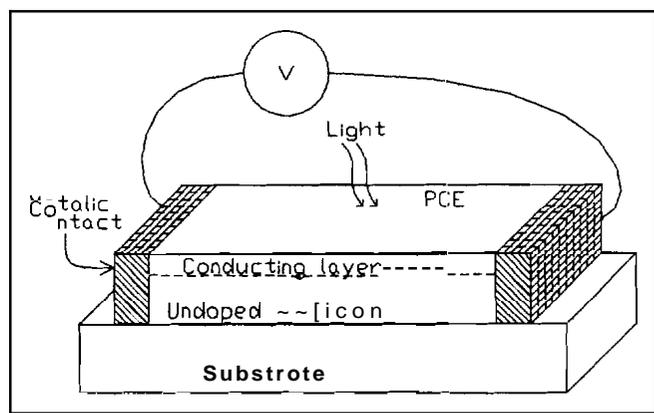


Figure V.12 PCE device geometry.

The PCE device has some key advantages which make it applicable to HVDC. It can be turned on and off very rapidly (on the order of microseconds), will conduct very large currents, hold off very high voltages and can be made extremely compact. It is also a bilateral device which makes it effective for both ac and dc switching applications. In contrast to standard solid state devices, switching speed is independent of size which allows fast control of high voltages. For example, a single silicon PCE operating at a voltage of 150kV has been used by Nunnally<sup>[15]</sup> to switch a 225 MW pulse into a matched resistive load using only 20 mJ of 1.06 micron laser energy. Note that silicon is the attractive material of choice because large, quality crystals are readily available and it has a long absorption depth which permits a large conductive volume (see the conduction layer in Figure V.12).

## V.13

The primary application of PCE material is in improving HVDC circuit breakers. PCE offers simple arc extinction and fast fault interruption. The circuit interruption sequence can be described as follows with the help of Figure V.13. At the onset of a fault, the PCE is turned on and the ac circuit breaker is opened, however, the PCE switch is much faster than the mechanical contacts in the breaker. Therefore, The **PCE** is considered to be fully turned on before the mechanical contacts begin to open. As such, the PCE provides a current path for the fault current which quickly extinguishes any arc that forms across the breaker contacts as they open. After about 200 microseconds, the PCE is turned off. The capacitor in the circuit, which keeps the voltage across the breaker from rising excessively fast, now begins to charge. As it charges, the voltage eventually rises until the turn on voltage of the varistor is reached. The varistor then dissipates any inductively stored magnetic energy in the system. Once the magnetic energy is dissipated, the current is finally interrupted. Studies have shown<sup>[15]</sup> that PCE breakers can interrupt higher currents in only a fraction of the time as obtained by conventional means. For a detailed description of a conventional HVDC breaker the reader is referred to [16].

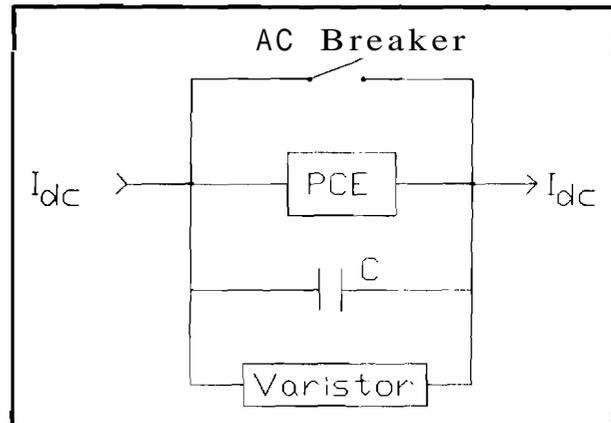


Figure V.13 HVDC circuit breaker.

Solid state devices have been the driving force behind the electronics industry for many years. Hopefully, this section has shown that even the power industry is not beyond the reach of semiconductor technology. Driven by the explosive nature of the computer industry, semiconductors can be expected to play an ever increasing role in the power industry as well as every aspect of electronics.

## V.5 Conclusions

The world-wide growth of HVDC transmission systems has accelerated significantly over the past ten years. Particularly in North America, HVDC is being applied to a variety of power transmission configurations. The economic, performance and environmental advantages that HVDC offer over other alternatives are the main reasons for this growth. Difficulties in gaining new right of way especially favors HVDC because it can offer greatly increased power flow over an

## V. 14

existing right of way currently being used for HVAC. Also, with technologies associated with HVDC being amply researched, the cost of HVDC: will continue to drop. To show the scope of the research activity, the areas receiving attention include: compact dc converters for metropolitan application, transformer dielectrics, HVDC circuit breakers, control system **developments**, dc insulator development, system study projects encompassing insulation **coordination**, radio interference, harmonic effects and thyristor **developments**<sup>[5]</sup>.

Hopefully, this chapter has shown that HVDC is going to play an increasing role in the future of power distribution. There is ample opportunity to participate in this developing field, which encompasses essentially every aspect of electric utility systems, with emphasis on solid state devices and control **theory**.

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