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# PROCEEDINGS OF A SEMINAR ON REACTIVE POWER, RESERVE CAPACITY, AND ALTERNATIVE METHODS OF DETERMINING ELECTRICITY PRICES IN WHOLESALE MARKETS

Riga, Latvia
November 19-20, 1992

*Prepared for:*

Bureau for Europe
**U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT**
Washington, D.C. 20523

HBI Reference No. 92-4070-205

*Prepared by:*

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November 1992

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**DESCRIPTION OF THE SEMINAR**

**AGENDA**

**LIST OF PARTICIPANTS**

**PAPERS PRESENTED:**

- William H. Dunn, Jr. "Consumption of Excess Reactive Power."
- William H. Dunn, Jr. "Measurement of Reserve Capacity and Definition of Reserve Obligations."
- Charles F. Zimmermann. "Alternative Methods of Determining Electricity Prices in Wholesale Markets."

## DESCRIPTION OF THE SEMINAR

On November 19 and 20, 1992, a seminar on electric power agreements and transactions was held at the Baltija Dispatch Center in Riga, Latvia. This seminar was organized by the Dispatch Center in cooperation with the U.S. Agency for International Development (AID) and with RCG/Hagler, Bailly, Inc., a U.S. consulting firm whose participation in the seminar was funded by AID's Bureau for Europe. Participants from Estonia, Latvia, and Lithuania attended the seminar and took part in the discussions. Presentations were given by two representatives of the Baltija Dispatch Center and by two U.S. consultants. The seminar focused on three topics:

- consumption of excess reactive power
- measurement of reserve capacity and definition of reserve obligations
- alternative methods of determining electricity prices in wholesale markets.

The key participants in the seminar are the members of a working group on electric power contracting and pricing. The members of this working group were selected on September 10, 1992 in accordance with a decision of the Baltic Energy Council, an organization containing representatives of the three power systems (Eesti Energia, Latvenergo, and the Lithuanian State Power System) and the three energy ministries (the Estonian Ministry of Energy, the Latvian Ministry of Industry and Energy, and the Lithuanian Ministry of Energy). The Baltija Dispatch Center is a limited liability company that is owned by all three countries, managed by the Baltic Energy Council, and funded by the three power systems. In this context the Baltic Energy Council has a management role that is comparable to the role of the board of directors of a private corporation. The responsibility of the working group is to assist the Baltic Energy Council in developing international agreements on electric power interconnections, sales, and wheeling.

The working group includes representatives of Eesti Energi, Latvenergo, the Lithuanian State Power System, and the Baltija Dispatch Center. The Estonian Ministry of Energy, the Latvian Ministry of Industry and Energy, and the Lithuanian Ministry of Energy were invited to send representatives to the seminar. The Latvian and Lithuanian ministries were represented but the Estonian ministry was unable to send a representative in the November 19-20 time frame.

The topics for the November seminar were selected by the working group at its first meeting, which was held at the Baltija Dispatch Center on October 14 and 15, 1992. The role of U.S. consultants in the seminar was to provide information to the working group on the types of

interconnection agreements and power sales agreements made by power systems in the United States, Canada, western Europe, and Australia.

The seminar had three objectives:

1. Discuss methods of coping with reactive power surpluses in the Baltic power systems and the way in which the cost associated with artificial consumption of reactive power should be shared among the Baltic power systems.

   This issue is related to the broader question of how the three countries should share the cost of maintaining and operating a transmission grid that was built as a unified system across Estonia, Latvia, Lithuania, and portions of Russia and Belarus. When the level of power flows is substantially below the level for which the transmission system was designed, a surplus of reactive power can develop. In 1992 the surplus of reactive power became a serious problem and the cost of compensating for this surplus became significant; selected hydro units were operated in synchronous condensor mode.

2. Discuss the methods of measuring the amount of reserve capacity that is actually available to meet load in the Baltic countries, the obligations of one power system to provide reserve capacity to another, and the method of payment for reserve capacity provided to another power system or systems.

   This issue is related to the question of how the three countries should share access to the generating capacity that was built as a part of the Northwest Interconnected Power System and sited without regard to the boundaries that have now become international borders. An agreement is needed to provide enough reserves to make up for an unscheduled shutdown of one of the 1300 MW Ignalina nuclear units. Without such a reserve, a nuclear unit shutdown would cause an immediate curtailment of power to customers.

3. Discuss alternative methods of determining electricity prices in wholesale markets.

   The Baltic countries are involved in international electric power sales transactions for which it is difficult to determine the appropriate prices to be charged. An agreement on the method of determining prices would facilitate the negotiation of prices.

All three topics were discussed, but specific or detailed agreements were not developed during the seminar.

This seminar is the first in a series of three seminars in an electric power contracting and pricing program funded by AID. The broader objectives of this program are:

(1) To work with the Baltic countries on developing acceptable terms and conditions of electric power transactions among these countries

(2) To promote the development of pricing principles that are consistent with the efficient operation of the regional electric system and consistent with economic efficiency objectives.

(3) To provide information to the Baltic countries regarding the choices that are available regarding electric power pooling arrangements, contracting arrangements, and tariff structures.

Before the working group on power contracting and pricing was formed by the Baltic Energy Council, two regional seminars were organized and implemented with AID funding. A seminar on international power pricing was held at the Baltija Dispatch Center on May 27-28, 1992, and a regional seminar on energy pricing was held at the Institute of Physical Energetics of the Latvian Academy of Sciences on July 16-17, 1992. These earlier seminars covered topics related to electricity pricing, including the terms of power pooling agreements and the development of tariffs based on marginal cost pricing principles.

**Seminar on Reactive Power, Reserve Capacity, and Alternative Methods of Determining Electricity Prices in Wholesale Markets**

**Agenda**

**Location:** Dispatch Center Baltija, 1 Shmerla str., Riga, Latvia

**Date:** Thursday, November 19 and Friday, November 20, 1992

**Countries involved:** Estonia, Latvia, Lithuania

**Agenda for November 19, 1992**

| | |
|---|---|
| *9:30* | Registration of participants |
| *10:00* | Introductory remarks by Vilnis Kreslinsh, director of DC Baltija. |
| *10:30* | Presentation by Juri Pervushin (DC Baltija) on reactive power compensation in the Baltic power systems in 1992. |
| *11:00* | Presentation by William Dunn (RCG/Hagler, Bailly, Inc.) on consumption of excess reactive power. |
| *11:30* | Discussion led by Metcheslav Vonsovich (DC Baltija) of proposals regarding excess reactive power. |
| *13:30* | Lunch |
| *15:00* | Presentation by Metcheslav Vonsovich (DC Baltija) on the present situation with regard to availability of reserve capacity. Identification of issues to be resolved. |
| *15:20* | Presentation by William Dunn (RCG/Hagler, Bailly, Inc.) on measurement of reserve capacity and definition of reserve obligations in the New England Power Pool and in the Nordel system. |
| *17:05* | Break |
| *17:20* | Discussion led by Metcheslav Vonsovich (DC Baltija) of proposals for measurement of reserve capacity and definition of reserve capacity obligations. |

**Agenda for November 20, 1992**

| | |
|---|---|
| *9:30* | Meeting of the working group |
| *10:00* | Discussion led by Metcheslav Vonsovich (DC Baltija) of proposals for measurement of reserve capacity and definition of reserve capacity obligations. (continued) |
| *11:00* | Presentation by Charles Zimmermann (RCG/Hagler, Bailly, Inc.) on alternative methods of determining electricity prices in wholesale markets. |
| *13:30* | Lunch |
| *14:20* | Discussion led by Metcheslav Vonsovich (DC Baltija) on alternative methods of determining electricity prices in wholesale markets. |
| *16:00* | Closing remarks by Vilnis Kreslinsh (DC Baltija), Charles Zimmermann (RCG/Hagler, Bailly, Inc.), William Dunn (ECC, Inc.) |

**Seminar on Reactive Power, Reserve Capacity, and Alternative Methods of Determining Electricity Prices in Wholesale Markets**

**Riga, Latvia**
**November 19-20, 1992**

List of Participants

**USA**

| | |
|---|---|
| Charles F. Zimmermann | RCG/Hagler, Bailly, Inc., Manager |
| William Dunn | ECC, Inc., Principal Consultant |

**DISPATCH CENTER BALTIJA**

| | |
|---|---|
| Vilnis Kreslinsh | Director of Dispatch Center Baltija |
| Metcheslav Vonsovich | Chief Engineer of Dispatch Center Baltija |
| Juri Pervushin | Deputy Chief of Grid Network Planning |
| Janis Ositis | Chief of Dispatch Department |
| Karl Brinkis | Chief of Relay Protection and Grid Network Planning |
| Tatiana Ovsjukova | Chief Specialist |

**ESTONIA**

| | |
|---|---|
| Valerij Peterson | Chief of Dispatch Department of Eesti Energia |
| Joulo Mejbaum | Deputy Chief of Dispatch Department of Eesti Energia |
| Mikel Viese | Control Engineer of Dispatch Department of Eesti Energia |

**LATVIA**

| | |
|---|---|
| A. Berzinsh | Ministry of Industry and Energy |
| Leons Marcinkus | Chief of Economics Department of Latvenergo |
| Eduards Rozental | Chief of Dispatch Department of Latvenergo |
| Peteris Klavinsh | Chief of Planning Department of Energocontrol Division of Latvenergo |

**LITHUANIA**

| | |
|---|---|
| Ada Maceziskiene | Ministry of Energy |
| Janas Balinskis | Deputy Director of LSPS |
| Gedeminas Volskis | Chief of Economic Department of LSPS |
| Augustinas Kiselius | Deputy Chief of Dispatch Department of LSPS |

# CONSUMPTION OF EXCESS REACTIVE POWER

Prepared for:

Seminar on Electric Power Contracting and Pricing
in Estonia, Latvia, and Lithuania
19-20 November 1992

**Control Center of the Baltic Power Systems Ltd.**
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# REACTIVE POWER CONTROL

- Reactive Power control means voltage control

- Why control voltage?

  - Prevent damage to power system equipment

  - Satisfactory voltage to customers/loads

  - Reduce system losses

# SOURCES OF REACTIVE POWER

- Generators running over-excited
- Static Capacitors
- Static Var Compensators (SVC)
- Line Charging
- Synchronous Condensors

Also,

- Under-Load Tap Changing transformers can move Reactive Power between voltage levels

# CONSUMPTION OF REACTIVE POWER

- Generators running under-excited
- Load (without compensating distribution capacitors)
- Static Var Compensators (SVC)
- Reactors
- Synchronous Condensors
- Transformers
- Line Loading

## WAYS TO CONTROL REACTIVE POWER

- Change generator excitation
- Switch capacitors/reactors/SVC
  - SCADA
  - Voltage Control
  - Time Clock
- Switch lines
- Adjust Under-Load Tap Changing transformers
- Start synchronous condensors, including:
  - Decoupled combustion turbines
  - Hydro units in synchronous condensor mode



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## BEFORE STARTING SYNCHRONOUS CONDENSORS TO LOWER VOLTAGE

- Make sure all capacitors in the area have been switched out
- Make sure all reactors in the area have been switched in
- Make sure all SVC's in the area are in the Reactive Power absorption mode
- Make sure all generators in the area are running under-excited to the extent technically permissible
- Make sure all Under-Load Tap Changing transformers in the area are drawing Reactive Power away from the problem area, to the extent feasible. Use tap stagger between adjacent transformers to increase Reactive Power consumption.

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## BEFORE STARTING SYNCHRONOUS CONDENSORS

If that does not solve the problem:

- Switch out lines not needed for reliability

Then, if there is still a problem:

- Start synchronous condensors
- Start hydro units and/or decoupled combustion turbines in synchronous condensor mode

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# ESTABLISH REACTIVE POWER CRITERIA

- For Generation:
  - Leading and lagging power factor capability
  - Voltage Schedules (vary by time of day and season)
- For Transmission/Distribution:
  - All capacitors and reactors switchable
  - SVC's, where appropriate
  - Under-Load Tap Changing transformers, where appropriate

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## ESTABLISH REACTIVE POWER CRITERIA

- For Load:
  - Power factor, as seen from the transmission system, within defined power factor range. Such range should vary with load level and season
  - Compliance with the above requires many capacitors to be switchable
  - Retail tariffs with power factor requirements and/or billing

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# RECOMMENDATIONS

- At this stage of development, the Baltics do <u>not</u> need a complex Reactive Power billing system

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## RECOMMENDATIONS

- Therefore, if modified dispatch of Reactive Power sources and consumption does not resolve the problem, the following actions could be taken:

  - Treat Real Power consumption for Reactive Power control (in synchronous condensors and in decoupled combustion turbines and hydro units operating in a synchronous condensor mode), as:

    1. Increased transmission losses to be shared by all three countries

    2. An expense of the transmission system (priced at marginal energy cost) and allocated as part of transmission system costs

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## RECOMMENDATIONS

- Develop penalty charges for non-compliance with criteria applicable to:

  1. Generators not producing or absorbing Reactive Power as required

  2. Load not within power factor criteria

  Pricing for these penalties could relate to the projected cost of compliance

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# MEASUREMENT OF RESERVE CAPACITY
# &
# DEFINITION OF RESERVE OBLIGATIONS

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# MEASUREMENT OF RESERVE CAPACITY



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# TWO TYPES OF RESERVE

- **Installed Reserve**

  **Probabilistically determined amount of total installed capacity needed to meet desired level of reliability while recognizing variability of load, generation availability and mutual assistance**

- **Operating Reserve**

  **Amount of spinning (synchronized) and fast start reserve capability needed to preserve the integrity of the system following a worst contingency and to restore the system to be able to handle the next contingency within a defined time period.**



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# MEASUREMENT OF RESERVE CAPABILITY

- **Installed Reserve**

  **The total audited capability of all generating resources of a utility including purchases from other utilities that are backed-up by audited capability**

- **Operating Reserve**

  **The difference between each operating unit's actual output and its audited capability, less any temporary limitations, plus the audited capability of any off-line fast start units, less any temporary limitations**

# DEMAND-SIDE MANAGEMENT (DSM)

- DSM can contribute to both Installed Reserve and Operating Reserve obligations
- Installed Reserve DSM can include techniques such as slow response:
  - Interruptible Loads
  - Customer Generation

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## DEMAND-SIDE MANAGEMENT (DSM)

- Operating Reserve DSM can handle techniques such as fast response:
  - Interruptible Loads
  - Customer Generation
  - Remote control of uses such as water heating, space heating, etc.
  - Voltage reduction
  - Other operator controlled demand reducing actions

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# HOW TO AUDIT CAPABILITY

## Installed Reserve

- Seasonal testing of capability under defined conditions:
  - Number of hours
  - Ambient temperature, if applicable
  - River flow, if applicable
  - Station configuration
- Details of "proof" required must be elaborated
- Occasional unannounced "spot tests" (say, 1 per month) should be allowed to validate ratings during actual day-to-day operations
- Additional complexity for multiple ratings (i.e. normal, reserve and maximum)

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# HOW TO AUDIT CAPABILITY

## Operating Reserve

- On-Line testing of response rates:

  Periodic (say, 1 per month) testing of the MW/Minute response rate of units under both manual and automatic control, if applicable

- Off-Line testing of fast start units:

  Periodic (say, 1 per month) testing of the time it takes off-line fast start units to get on-line and fully loaded

- Details of "proof" required in both cases must be elaborated

- Additional complexity for multiple ratings (i.e. normal, reserve, maximum)

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# HOW TO AUDIT CAPABILITY

## Demand-Side Management (DSM)

- Seasonal testing of response and MW of load relief actual achievable from:
  - Interruptible Loads
  - Customer Generation
  - Operator initiated remote control
  - Voltage reduction
- Details of "proof" required must be elaborated
- If customer payments are associated with DSM capability, penalties must be included for non-performance

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# DEFINITION OF

# RESERVE OBLIGATIONS



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# INSTALLED CAPACITY OBLIGATIONS

## Northeast Power Coordinating Council (NPCC)*

"Each Area's generating capability will be planned in such a manner that, after due allowance for scheduled maintenance, forced and partial outages, interconnections with neighboring Areas and regions, and available operating procedures, the probability of disconnecting non-interruptible customers due to generation deficiency, on the average, will be no more than once in ten years."

* NPCC is 1 of the 9 Regional Councils of the North American Electric Reliability Council (NERC). The New England Power Pool (NEPOOL) is one of the Areas of NPCC.

# OPERATING RESERVE OBLIGATIONS

## Northeast Power Coordinating Council (NPCC)

"Each Area shall make every effort to schedule outages of generating capacity in such a manner that generating supply, with allowance for forced outages, will be adequate to meet the Area's forecasted load and reserve requirements, in accordance with the NPCC Operating Reserve Criteria."

The NPCC Operating Reserves Criteria cover:

- Ten-Minute Reserve (including synchronized or spinning component)
- Thirty-Minute Reserve
- Automatic Generating Control (AGC)
- Distribution (Pattern) of Reserve
- Sustainability of Reserve



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# MEETING OBLIGATIONS

## Two Approaches

- Each utility does it on their own
- Groups of utilities do it by cooperating:
  - On a bilateral bases
  - Through a pooling arrangement

# FIRST EXAMPLE OF POOLING OF INSTALLED CAPACITY OBLIGATIONS & OPERATING RESERVE OBLIGATIONS

## New England Power Pool (NEPOOL)

# NEPOOL

## POOLWIDE INSTALLED CAPACITY REQUIREMENT
(Objective Capability)

## LEADS TO PARTICIPANT CAPABILITY RESPONSIBILITIES

- 70% weighted by respective annual peaks
- 30% weighted by respective average monthly peaks
- influenced by:
  - Performance Incentive Program
  - New Units
  - Tie Line Adjustment
  - Adjustment and Deficiency Charges

# NEPOOL

## PERFORMANCE INCENTIVE PROGRAM (PIP)

- Compares actual availability to the target availability (by class of unit) used in setting Objective Capability
- Does it by unit entitlement (share)
- Adjusts each Participant's Capability Responsibility based on the weighted difference between actual and target availability for its units
- The adjustment is done at the rate corresponding to changes in NEPOOL's Objective Capability for incremental changes in all target availabilities
- "Safety Net" protects against impact of catastrophic failure (reason for pooling)

# NEPOOL

## NEW UNITS

A way of allocating the incremental reliability benefits/impacts from the design performance of a New Unit

- Calculate Objective Capability using the characteristics and target availabilities of all units including the New Units
- Calculate Objective Capability replacing the New Units with "Proxy" unit characteristics and target availabilities (400 MW, 10.85% forced outage rate, 9.62% planned outage rate, 2.3% summer derating)

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# NEPOOL

## NEW UNITS

- The Objective Capability calculated using the Proxy Units is used to determine initial Capability Responsibilities for the Participants
- The difference between the two Objective Capability calculations is charged or credited to the Participants holding the entitlements in the New Units
- The PIP also applies to the New Units

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# NEPOOL

## TIE LINE ADJUSTMENTS

- Objective Capability is calculated assuming certain transfer capabilities and emergency assistance available between NEPOOL and other adjoining pools/utilities
- Objective Capability is calculated assuming certain contractual usage of a portion of these transfer capabilities
- If actual contractual use for meeting Capability Responsibility requirements is different from that assumed in setting Objective Capability, an adjustment to required Objective Capability is performed

# NEPOOL

## ADJUSTMENT & DEFICIENCY CHARGES

- Approximates the carrying charges of installing new combustion turbine peaking capacity, together with an allowance for associated wheeling costs

  Adjustment Charge: US $72/KW-Yr

  Deficiency Charge: US $33/KW-Yr

- Deficiency charges can be waived for circumstances beyond the control of the Participant

# NEPOOL

## OPERATING RESERVE

Sufficient units are kept on Automatic Generation Control (AGC) to insure that tie lines to external pools/utilities are at scheduled values and the frequency is maintained at 60.00 Hz ± 0.02 Hz

Sufficient reserve is maintained to cover 1-½ times the largest contingency. Of this total reserve:

- 1/3 is available in 30 minutes
- 2/3 is available in 10 minutes (at least ⅔ of the 10 minute reserve has to be synchronized and at least ½ of that has to be on AGC)



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# SECOND EXAMPLE OF POOLING OF INSTALLED CAPACITY OBLIGATIONS & OPERATING RESERVE OBLIGATIONS

## Scandinavian Power Pool (NORDEL)

# NORDEL

Each country is responsible for maintaining, at all times, its share of the regulation response and production reserves required in NORDEL. There is no Installed Capacity Obligation, as such.



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# NORDEL

- Each country prepares its own "power and energy balance" for the next three years
- These are compiled by the NORDEL Operations Committee and distributed
- The plans for the next year allow identification of possible and suitable exchanges of power and/or energy to cover outages
- Bilateral meetings are held throughout the year between the owners of the interconnections
- These meetings serve to identify where outage plans can be modified to minimize total costs or maintain operational security

# NORDEL

## WEEKLY INFORMATION EXCHANGE

- Each week, the operations management personnel in each country exchange information on:
  - The largest loss of production which can occur
  - Planned line-outages
  - Transmission limitations on the tie lines and in the national networks
  - Operating reserves
  - Forecast marginal values
- Each country follows NORDEL guidelines to determine its marginal cost of energy

# NORDEL

## ACTUAL DISPATCH

- Each country determines the optimum dispatch of its resources to meet the demands of its customers at the lowest cost
- This leads to determination of each country's marginal cost of energy, which are exchanged with the other countries
- Agreements are made on power exchanges:
  - shall be made with regard to valid notification time, usually 1 hour
  - shall specify the amount and duration, usually 1 to several hours
  - shall specify the price, usually the average of buyer's and seller's marginal values



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# NORDEL

## PRODUCTION CONTROL

- Primary regulation is usually set at 6,000 MW/Hz
- Responsibility for primary regulation is allocated in proportion to annual consumption as follows:

| | |
|---|---|
| Norway | 1,940 |
| Sweden | 2,630 |
| Finland | 1,160 |
| Denmark | 270 |

- Primary regulation responsibility can be met by purchases from another country
- Deviations from scheduled interchange are priced in accordance to agreements which are specific to the interconnection involved

# NORDEL

## PRODUCTION RESERVES

- Operating reserve is broken down into two categories:
  - Normal operating reserve is available for frequency regulation and to cover deviations from forecasts
  - Disturbance reserve is for disturbances in the power balance or in the transmission system
- Activation time for both normal and disturbance reserves is subdivided into:
  - Instantaneous reserve maximum of 30 seconds
  - Fast reserve maximum of 15 minutes
  - Slow reserve maximum of 4 hours

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# NORDEL

## PRODUCTION RESERVES

- The instantaneous component of both normal and disturbance operating reserve is covered by the production control MW/Hz requirements

- The fast and slow components of both normal and disturbance operating reserves are dimensioned after local criteria and are not coordinated within NORDEL on a regular basis

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# NORDEL

## DAILY NORDIC POWER EXCHANGES

- Each country determines its marginal power value following NORDEL standards for calculation
- Most exchanges are transacted on a split the savings basis
- In cases where the purchasing country does not have self generation options or where the costs of their options are extreme, a cap is placed on the seller's price of 75 SEK/MWh above its marginal cost to supply
- These daily power exchanges are conducted to minimize total production costs and to:
  - utilize the combined hydro resources and avoid spilling
  - utilize the combined nuclear resources optimally
  - utilize fossil resources in cost order

# NORDEL

## OTHER CHARACTERISTICS

- Denmark and Finland are power dimensioned. This means that if the power stations have sufficient capacity to cover maximum demand, there is no problem with covering the energy requirements.

- Sweden and Norway are energy dimensioned. This means that if the annual energy demand can be satisfied, there is no problem covering the maximum demand.

- The large variations in annual hydro production are balanced by transfers between the power dimensioned and energy dimensioned systems

- Participation in power exchanges is voluntary

# ALTERNATIVE METHODS OF DETERMINING ELECTRICITY PRICES IN WHOLESALE MARKETS

Prepared for:

Seminar on Electric Power Contracting and Pricing
in Estonia, Latvia, and Lithuania
November 19-20, 1992

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Washington, D.C. 20523

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# ALTERNATIVE METHODS OF DETERMINING ELECTRICITY PRICES IN WHOLESALE MARKETS

Objectives of this presentation:

- to provide information regarding the alternative methods that could be used to determine the prices of electricity purchased and sold by Baltic countries

- to identify pricing methods that are consistent with the efficient operation of the regional power system and consistent with economic efficiency objectives.

Funding for U.S. participation in this seminar is provided by the U.S. Agency for International Development (AID). AID's broader objective is to help the Baltic countries make a transition to a market economy.



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## TRANSACTIONS WITHIN THE SCOPE OF THIS PRESENTATION

**Sale of both capacity and energy**

If power system A has a contract to provide baseload capacity for system B, it will be normal for B to purchase energy generated from this capacity. Most power sales transactions involve capacity and energy.

**Sale of electric energy (without the sale of capacity)**

(1) If power system A can generate electricity more cheaply than system B, it is possible for A to deliver energy to B on a short-term basis, without making a long-term commitment to provide capacity to B.

(2) If A and B cannot agree on the terms of a capacity contract, it is possible that A and B will be able to negotiate the sale of energy alone.

**Sale of electric generating capacity (and energy, when needed)**

It is possible for power system A to have a contract to maintain reserve capacity for system B, and receive payment for this reserve, even when the capacity is not used to deliver energy to B.

## TRANSACTIONS OUTSIDE THE SCOPE OF THIS PRESENTATION

**Energy exchange**

(1) Power systems A and B may find that it is cheaper to exchange energy with each other at different locations than to generate and transmit energy without such exchanges.

(2) If power system A can deliver energy to system B and B can deliver an equivalent amount of energy to system C without transmitting energy received from A, it will be possible for A to provide energy to C by negotiating an exchange agreement with B. Under this agreement B delivers energy to C, in exchange for the energy received from A.

**Sale of both transmission capacity and transmission service**

If power system A has a contract to provide transmission capacity for the benefit of system B, it will be normal for B to use this capacity to transmit energy.

**Sale of transmission service (without the sale of capacity)**

It is possible for A to provide transmission service to B on a short-term basis, without making a long-term commitment to provide transmission capacity to B.

## DEFINITIONS OF SELECTED TERMS

Power system

For this presentation, a power system is defined as an enterprise which owns generation, transmission, and distribution facilities. Examples are Eesti Energia, Latvenergo, and the Lithuanian State Power System. Power systems in the United States are owned by private companies and by the federal government, state governments, and city governments.

Customer

A customer is an individual, an industrial enterprise, a government institution, or a power system that purchases electricity or pays for transmission services. Any organization that is billed for electricity use is a customer. For example, Latvenergo is a customer of Eesti Energia.

Consumer

An electricity consumer is a customer who does not sell, generate, transmit, or distribute electricity.

Wholesale market

A power system can sell electricity in two markets: (1) a retail market, in which electricity is sold to consumers, and (2) a wholesale market, in which electricity is sold to other power systems (or to a grid company that does not sell to consumers).

Electricity prices

Electricity prices include all of the prices related to the sale of electricity, and may include energy charges, demand charges, customer charges, and charges for reactive power.

Methods of determining prices

A method of determining prices is a set of general concepts and principles used to calculate prices. The selection of a method reflects an economic philosophy as well as technical considerations.

## DEFINITIONS OF TERMS

Domestic market

For a power system, the domestic market includes all of the customers located within the country where the power system is located. For Eesti Energia, Latvenergo, and the Lithuanian State Power System (LSPS) the domestic market is only a retail consumer market. For many U.S. utilities the domestic market includes both a retail and a wholesale market.

Export market

Electricity is exported when it is sold by a power system in one country to a customer in another country. It is normal in market economies for the export market to be limited to a wholesale market. Therefore an export market is a particular kind of wholesale power market - one in which international trade is involved.

When both the exporting nation and the importing nation have hard currencies, power import and export agreements can be very similar to other types of wholesale power agreements. For example, agreements between U.S. and Canadian power systems are similar to agreements among U.S. power systems.

Power pool

A power pool is an association of two or more interconnected power systems having an agreement to coordinate operations and planning for improved reliability and efficiency. Because Eesti Energia, Latvenergo, and the Lithuanian State Power System have agreed to coordinate operations through the Baltija Dispatch Center, they are part of a power pool. The Northwest Interconnected Power System was a power pool.

Reliability council

In the United States and Canada, a reliability council is an association that is formed to promote the reliability and adequacy of power supply over a large region. The ten reliability councils cover all of the United States and Canada. Two of these reliability councils are power pools. The North American Electric Reliability Council (NERC) is a federation of the ten regional reliability councils.

## TERMS USED IN ELECTRIC RATE DESIGN

### Customer class

A customer class is a category of customers that is distinguished for the purpose of calculating tariffs. In former socialist economies there may be only two customer classes, household and industrial. Customer classes in the United States include residential, commercial (or "small light and power"), industrial (or "large light and power"), public street and highway lighting, other public authorities, railroads, and wholesale customers.

### Revenue requirement

It is possible to calculate tariffs so that for planning purposes, total annual revenue equals total annual cost (including an allowance for a return on capital investment). This total annual cost is called the revenue requirement.

Revenue requirement = Capital carrying charge + Fuel cost + Operating cost + Maintenance cost

### Capital carrying charge

The capital carrying charge (or annual capital cost) is the amount of revenue needed to pay interest on debt, profit on shareholders' equity, depreciation, amortization, income taxes, and taxes on the value of land, buildings and equipment owned by the power system. (For more information see U.S. Department of Energy, Electric Plant Cost and Production Expenses 1990, pages 126-128.)

### Allowed rate of return on equity

In the United States power sector the profits of shareholding companies are limited by price controls that are set by state governments and by the Federal Energy Regulatory Commission (FERC). To set acceptable price levels the regulatory authority must determine the annual percentage rate of return on shareholders' equity capital that should be allowed. This percentage is called the allowed rate of return on equity. This rate is usually determined by estimating the rate needed to attract equity capital.

## A Method for Estimating Generation Expenses for Power Plants*

**Generation expense =**
**Capital carrying charge + Fuel expenses +**
**Operation expenses + Maintenance expenses**

**Capital carrying charge =**
**(Net investment in plant x Rate of return) + Income taxes**
**+ Depreciation and amortization + Taxes other than income taxes**

**Net investment in plant =**
**Gross investment in power plant - Accumulated depreciation**
**- Deferred income taxes - Deferred income tax credit**
**+ Working capital**

**Accumulated depreciation =**
**(Age of power plant / Assumed economic life of power plant)**
**x Gross investment in power plant**

**Working capital =**
**Annual fuel and operation and maintenance expenses / 8**

**Rate of return =**
**(Common stockholders' share of capitalization**
**x Rate of return on common stock)**
**+ (Preferred stockholders' share**
**x Rate of return on preferred stock)**
**+ (Debt share of capitalization**
**x Average interest rate on debt)**

**Depreciation and amortization =**
**Gross investment in power plant / Economic life of plant**

* This method was developed by the U.S. Department of Energy to compute generation expenses for individual power plants. To set tariffs it is usually not necessary for a power system to calculate capital carrying charges for individual stations.
Source: U.S. Department of Energy, Energy Information Administration, Electric Plant Cost and Power Production Expenses 1990, DOE/EIA-0455(90), pages 11, 126-128.

## TERMS USED IN ELECTRIC RATE DESIGN

Fully distributed cost

When the revenue requirement is allocated among customer classes, the cost to a particular customer class is called a fully distributed cost. This approach to pricing is commonly used when a power system cannot earn profits from exports (for example, when it is a net importer).

Fuel and purchased power adjustment clause

A fuel and purchased power adjustment clause is a tariff provision designed to ensure that an increase (or decrease) in the cost of fuel and/or purchased power is matched by an increase (or decrease) in revenue. When actual revenue exceeds actual cost there is a "cost over-recovery." When actual cost exceeds actual revenue there is a "cost under-recovery." The adjustment clause may be designed to eliminate both conditions.

## TERMS USED IN ELECTRIC RATE DESIGN

Short run marginal cost (SRMC) of energy

The SRMC of energy is the estimated cost per kWh of supplying an additional kWh of energy, at a particular hour of a particular day, using existing plant and equipment and using the available fuel supply. SRMC is often used to compute prices in short term economy transactions; for example, the price of economy energy may equal SRMC plus a profit allowance.

Short run marginal cost of capacity

If it is possible to sell additional capacity using existing plant and equipment, the SRMC of capacity is the estimated cost per kW of supplying an additional kW of capacity in a particular time frame (for example, the month of January) using existing plant and equipment and using the available fuel supply. The SRMC of capacity is a concept that is not commonly used in pricing.

Long run marginal cost (LRMC) of energy

The LRMC of energy is the projected cost per kWh of supplying an additional kWh of energy in a particular portion of the year (for example, the peak hours during the winter season) over a period of many years, using both new and existing plant and equipment and using fuel from the sources of supply that are planned for the future.

Long run marginal cost of capacity

The LRMC of capacity is the projected cost per kW of supplying an additional kW of capacity in a particular portion of the year (for example, the peak hours during the winter season) over a period of many years, using both new and existing plant and equipment and using fuel from the sources of supply that are planned for the future.

## ALTERNATIVE APPROACHES TO PRICING

Approaches based on distributed cost

1) Seller's fully distributed cost

2) Premium above seller's fully distributed cost

3) Seller's cost at specific generating stations

4) Split savings

Approaches based on marginal cost

5) Seller's SRMC (for recovery of variable cost)

6) Regional SRMC (for recovery of variable cost)

7) Regional SRMC (for recovery of fixed and variable cost)

8) Regional SRMC plus capacity charges

Approaches based on competitive bidding

9) Competitive bidding for energy

10) Competitive bidding for capacity

Approaches based on prices in other countries

11) Published prices *

12) Calculations based on generation cost *

* These approaches are not recommended and and are very rarely used in market economies, but are included for comparison.

No single approach is recognized as the standard in market economies.



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## APPROACHES BASED ON DISTRIBUTED COST

### Seller's fully distributed cost

The tariff system is designed to ensure that the seller's total revenue matches the seller's revenue requirement - the total annual cost (including profit) of providing electricity to retail (domestic) customers and wholesale (foreign) customers. Tariffs are intended to allocate costs fairly among customer classes. The same pricing principles are applied to domestic and foreign customers. The buyer is assured that the profits of the seller will not be excessive, but the buyer pays a share of the seller's cost increases. Export prices are raised when the seller faces low capacity utilization or high fuel prices. Adjustment clauses (for example, a fuel and purchased power adjustment clause) may be used to ensure that actual revenues match actual costs, for certain cost categories.

Revenue requirement = Domestic revenue + Export revenue

In the United States, tariffs to retail customers are usually based upon fully distributed costs. The concept is easily applied to wholesale customers.

Structure of export tariffs

Option 1: The seller does not dedicate firm capacity to the buyer, and the buyer pays an energy charge only. The energy charge may be adjusted hourly or daily. The sale can be terminated by the seller without notice.

Option 2: The seller agrees to dedicate firm capacity to the buyer, but the buyer pays an energy charge only. The energy charge includes an allowance designed to compensate the seller for the annual capital cost associated with this capacity commitment. The energy charge may be adjusted hourly, daily, or monthly.

Option 3: The seller agrees to dedicate firm capacity to the buyer, who pays a capacity charge and an energy charge. The capacity charge is computed to compensate the seller for the annual capital cost associated with the seller's capacity commitment. The energy charge may be adjusted hourly or daily. The capacity charge may be adjusted monthly or annually.



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## APPROACHES BASED ON DISTRIBUTED COST

### Premium above seller's fully distributed cost

In a power pool agreement, each power system may take responsibility for constructing and maintaining a certain amount of reserve capacity. When a power system must purchase electricity from other systems because it has a deficiency of capacity, the price of this electricity may include the seller's fully distributed cost plus a premium. This pricing system tends to encourage the construction of reserve capacity, which can be sold at a premium.

For example, the New England Power Pool (NEPOOL) has three types of outage service. In each category the price of electricity contains a premium:

- a 5 percent premium for Scheduled Outage Service (SOS)

  The premium is applied to either (1) the full load average rate for the buyer's generating unit out on scheduled outage or (2) the estimated average annual cost of supply for SOS, whichever is greater.

- a 10 percent premium for Unscheduled Outage Service

  The premium is applied to either (1) the full load average rate for the buyer's generating unit out on unscheduled outage or (2) the estimated average annual cost of supply for SOS or (3) the sellers' average actual hourly cost of supply for Unscheduled Outage Service, whichever is greater.

- a 15 percent premium for Deficiency Service

  The premium is applied to either (1) the estimated average annual cost of supply for SOS or (2) the seller's average actual hourly cost of supply for Deficiency Service, whichever is greater.

<u>Structure of export tariffs</u>

A premium can be applied to any tariff structure. Any of the three options described on the previous page (for seller's fully distributed cost) may be used.

## Premium above seller's fully distributed cost:

## Issues involving the distribution of operating profits

The seller's fully distributed cost is supposed to be sufficient to provide the seller with a reasonable return on invested capital. If the seller is able to sell power at a premium above fully distributed cost, the seller will earn additional operating profits. Where do the operating profits go?

There are several possible outcomes.

> Option A: Operating profits from electricity exports are added to the net income of shareholders, who may decide to use these funds to provide capital for the power system or use these funds to pay dividends.
>
> Option B: Operating profits from electricity exports are used to reduce tariffs to domestic customers.
>
> Option C: Operating profits from electricity exports are retained by the power system, but the power system is required to use these funds as a source of capital for investment.
>
> Option D: Operating profits from electricity exports are used to reduce the level of transfers from the government to the power system, or to increase the level of transfers from the power system to the government.

The choice among these outcomes must be made by governments. In the United States, options A and B are most commonly used. When the net income of shareholders is increased, however, the corporate income tax leads to an increase in payments to the federal government and (usually) the state government.

## APPROACHES BASED ON DISTRIBUTED COST

### Seller's cost at specific generating stations

The seller identifies specific generating stations that can be used to export capacity and energy. For each of these stations the seller calculates a tariff on the basis of standard operating assumptions consistent with the design of the plant. The buyer does not pay a premium when the seller has excess capacity and experiences low capacity utilization. For example, the annual capacity utilization for a baseload station may be assumed to be high, for the purpose of computing a tariff, regardless of the station's actual capacity utilization. For each station the tariff is computed from the seller's costs under the stated assumptions. For example, the tariff could be a price per kWh equal to:

- the station's "full load average rate" (the average cost per kWh assuming full load) or

- the station's average cost per kWh based on planned capacity utilization.

This approach is applied to some wholesale power sales in the United States.

There are at least two alternative methods of adjusting tariffs for fuel prices:

Option A: The energy charge is revised on a monthly basis to adjust for (1) changes in projected fuel prices and (2) the difference between actual and planned fuel costs incurred during the last 12 months.

Option B: The energy charge is based upon projected fuel costs, and revised on a monthly basis, without an adjustment for the difference between actual and planned fuel costs.

<u>Structure of export tariffs</u>

The three options available for the seller's fully distributed cost approach are also available for this approach.



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## APPROACHES BASED ON DISTRIBUTED COST

### Split savings

The seller has no contractual obligation to provide firm capacity to the buyer. The buyer does not need additional firm capacity. The purpose of the transaction is to minimize the operating cost of power generation in the region (by providing "economy power" to the buyer). The buyer is capable of generating the amount of energy involved in the power sales transaction, without buying the energy from the seller, but the buyer finds that it is cheaper to purchase energy than to generate it. The tariff is an energy charge equal to the seller's incremental cost of power generation, plus a premium. The energy charge is adjusted hourly, or is computed for each power sale transaction.

Before each power sale transaction, the buyer calculates his decremental cost per kWh and the seller calculates his incremental cost per kWh, and the information is shared. (In a power pool this information may be reported hourly to the dispatch center.) The price is equal to the average of the buyer's decremental cost and the seller's incremental cost.

Under this approach the seller receives half of the total savings that would have been realized by the buyer if the energy had been sold at the seller's incremental cost. The seller therefore can obtain extra operating profits from power exports.

## DEFINITIONS

Buyer's decremental cost

> For a specific amount of energy sold in a specific time period, the decremental cost is the difference between the buyer's actual generation cost during the period and the level of generation cost that the buyer would have incurred if the power sale transaction had not occurred.

Seller's incremental cost

> For a specific amount of energy sold in a specific time period, the seller's incremental cost is the difference between the seller's actual generation cost during the period and the level of generation cost that the seller would have incurred if the power sale transaction had not occurred.

**Split savings between NEPOOL and Hydro-Quebec**: Phase I agreement

The following text is found in the Phase I agreement between the New England Power Pool and Hydro-Quebec.

"Economy energy" is defined as energy derived from non-renewable resources and delivered in order to effect a saving in the cost of generation when the receiving party has adequate generating capability to carry its own load. Either party may terminate or suspend the supply of Economy Energy at any time on reasonable notice to the other. Unless otherwise agreed to by the Operating Committee for a specific delivery, the price to be paid for Economy Energy shall be the incremental cost to the supplying party plus one-half of the savings gained by the interchange. The savings gained by the interchange shall be determined by deducting the incremental cost to the supplying party from the decremental cost to the receiving party of such energy transfer.

(*Supplement III, part 1*)

The words "incremental cost" where used in the Agreement shall mean any cost incurred by one party hereto supplying energy to or making operating reserve available to the other, which would not otherwise be incurred if the transaction did not take place. The elements of incremental cost when energy is supplied from sources on the seller's system which are normally in operation for operating reserve or for other purposes shall include, but not be limited to, the following:

Any incremental fuel cost and/or water rental charge.
Any cost for energy purchased to replace stored hydraulic energy.
Any incremental maintenance cost.
Any incremental labour cost.
Any incremental cost of a miscellaneous nature such as, for example, coal handling, water spillage.
Any incremental transmission cost or savings.
Any applicable incremental taxes or grants in lieu of taxes.

(*Supplement II, part 1*)

**Split savings between NEPOOL and Hydro-Quebec:**
Phase I agreement (continued)

When energy is supplied from sources on the seller's system placed in operation for the specific and sole purpose of supplying energy or making operating reserve available to the other party, then the incremental cost shall include all costs referred to above and in addition, where applicable:

Any boiler firing-up cost.
Any boiler banking cost.
Any boiler incremental maintenance cost.
Any boiler incremental labour cost.
Any turbine starting cost.
Any turbine speed-no-load cost.
Any turbine incremental labour cost.

When energy is supplied from sources on the seller's system, then the incremental costs may include an allowance, computed by probability methods, for estimated present-day value of future costs which are expected to be incurred as a result of the transaction. The methods of computing and applying such allowances shall be agreed upon in writing by the Operating Committee.

(*Supplement II, part 1*)



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## Split savings

### An example from the New York Power Pool

The New York Power Pool includes all of the large electric power systems in the state of New York. Among these power systems there are a variety of agreements to sell capacity and energy, but the daily dispatch of economy energy by the power pool is based upon a relatively simple pricing principle. Generating units are dispatched on the basis of the variable cost of power generation; the units with the lowest variable cost are dispatched first. The cost of generation in the region is minimized by the dispatch procedure, according to the power pool agreement.

In the New York Power Pool, economy energy is sold under a form of split-savings agreement that covers many transactions among the power systems within the pool.

Buyers purchase economy energy from the pool, and sellers sell to the pool. Each seller is paid an amount equal to the seller's incremental cost and then receives one half of the difference between the seller's incremental cost and the weighted average decremental cost (the weighted average buying cost) of all buyers.

Each buyer pays an amount equal to the buyer's decremental cost and then is refunded half of the difference between the buyer's decremental cost and the weighted average incremental cost (the weighted average selling cost) of all sellers.

## APPROACHES BASED ON MARGINAL COST

### Seller's SRMC (for recovery of variable cost)

The seller has no contractual obligation to provide firm capacity to the buyer. The tariff is an energy charge equal to the seller's short-run marginal cost (SRMC) of energy. The energy charge may be adjusted hourly, or if hourly adjustment is not practical the energy charge may be adjusted daily, for peak and off-peak periods.

For each hour or each peak/off-peak period, each power system calculates its SRMC, and the information is shared. The power systems engage in bilateral transactions to reduce generating cost through power sales. In each hour or each peak/off-peak period, the seller charges a single price (his SRMC) to all buyers. A power system with a high SRMC will want to purchase energy from power systems with a low SRMC.

### Definition of SRMC

The term SRMC is used to refer to the SRMC of energy. In the United States the concept of SRMC of capacity is used very rarely, if ever, because capacity is not sold on a short-run basis (hourly or daily). The amount of generating capacity available from existing stations is projected annually for winter peak and summer peak periods, and capacity is sold in advance of the winter peak or summer peak. The amount of capacity specified in the contract may be adjusted to reflect seasonal variations in the capability of a generating unit (caused by changes in cooling water temperature or other factors) but is not adjusted daily.

The SRMC of energy is the estimated cost per kWh of supplying an additional kWh of energy, at a particular hour of a particular day, using existing plant and equipment and using the available fuel supply. In this context the generating resource that is used to supply an additional kWh is called the "marginal" resource. If generating resources are dispatched according to their variable cost per kWh, the marginal resource in a particular hour will be the one with the highest variable cost per kWh (among the resources used in that hour) and the SRMC will be the cost of an additional kWh from the marginal resource. In a transaction involving a modest increase in capacity utilization at a single generating station, the seller's SRMC could equal the seller's average incremental cost per kWh (the seller's incremental cost divided by the number of kWh sold).

## Seller's SRMC (for recovery of variable cost)

The components of SRMC depend on the type of power sale transaction for which a price must be determined.

- If the seller is a generating company and the buyer arranges for transmission, the seller's SRMC is simply the variable cost of generation (the additional fuel cost, operating cost, and maintenance cost) needed to supply an additional kWh of energy, at a particular hour of a particular day, using existing plant and equipment and using the fuel available. In the United States the marginal cost of generation is called the "system lambda" and this indicator is commonly used to dispatch generating stations.

- If the seller is a power system that provides transmission service as well as generation, the seller's SRMC should include an allowance for transmission losses, in addition to the variable cost of generation.

- If a group of power systems have formed a power pool, in which there are many transactions and it is impossible to predict who will be the sellers and who will be the buyers on a particular day, the power systems could decide that the seller's SRMC is the variable cost of generation. To develop a payment scheme it may not be necessary to estimate transmission losses for each transaction.

In a power pool or national grid, the buyer may pay a premium above the seller's SRMC, depending on the power pool's approach to reliability issues. A power system typically becomes less reliable during peak periods, as generating capacity reaches its maximum utilization and transmission capacity reaches its maximum utilization. If the price paid by the buyer is intended to reflect changes in the reliability of power supply, SRMC must include an allowance for the effect of an additional kWh of load on the reliability of power generation and transmission. This allowance is called a "congestion cost." In England and Wales it is computed as the Value of Lost Load (the average "price" per kWh assigned to energy that the customer is able to purchase but the power system cannot deliver) multiplied by the Loss of Load Probability (the probability that the power system will not be able to deliver the energy that the customer wants to purchase). The congestion cost is not a cost incurred by the seller; it is not part of the seller's SRMC.



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## Seller's SRMC (for recovery of variable cost)

Advantages

1. The seller is assured that no portion of his energy exports will be sold below the cost of providing the energy. No portion is "subsidized."

2. If the buyer is considering a marginal increase or decrease in the quantity of power purchased, the buyer's decision will be based upon a "correct" price signal - the cost associated with a marginal increase or decrease.

3. The seller's price does not depend upon information received from the buyer (for example, information regarding the buyer's decremental cost) or information received from other sellers (unlike "split savings.")

4. If consumer tariffs are based upon marginal cost pricing, it may be desirable to apply the same principles to export tariffs. Many economists (including World Bank economists) have supported the use of marginal cost pricing in consumer tariffs. When the consumer faces a decision whether to buy an additional kWh of electricity, it is desirable for the price of that additional kWh to reflect the true cost of supplying that kWh. If the consumer tariff contains demand charges and customer charges as well as energy charges, it may be argued that the energy charge should equal the power system's SRMC.

5. If the power systems want to establish a competitive market for wholesale power, this approach provides a transition to a competitive market.

Disadvantages

1. When there is a shortage of capacity or a shortage of fuel, this approach may be considered unfair. The seller's profits can become very high when SRMC rises above the seller's average cost of power generation.

2. This approach is suitable when there are no capacity commitments.

3. SRMC is constantly changing and therefore results in unstable prices.

4. This approach does not offer a way to distribute the potential savings from power interchange fairly.

5. This approach is somewhat theoretical and experimental.

## APPROACHES BASED ON MARGINAL COST

A regional SRMC can be implemented in three ways:

**Regional SRMC (for recovery of variable cost)**

In a region where the power systems do not need to negotiate contracts for the sale of capacity, or the power systems have not been able to agree on the terms of capacity contracts, the regional SRMC may be used to set prices that are intended to recover only the variable costs of generation and transmission.

**Regional SRMC (for recovery of fixed and variable cost)**

In a region where there is a need for sellers to recover the cost of capacity through export prices, the regional SRMC may be used to set prices that are intended to recover capacity costs and other fixed costs in addition to the variable costs of power generation and transmission.

This situation exists in England and Wales, where the National Grid Company establishes a Pool Purchase Price equal to the System Marginal Price plus an allowance for the effect of additional generation on reliability. This allowance equals the Value of Lost Load multiplied by the Loss of Load Probability.

**Regional SRMC plus capacity charges**

In a region where there is a need for sellers to recover the cost of capacity through export prices, the regional SRMC may be used to set an energy charge that is supplemented by capacity charges. The capacity charges are intended to recover capacity costs and other fixed costs, while the energy charges are intended to recover only the variable costs.

An example of a U.S. power pool with a regional energy rate based on SRMC is the Pennsylvania-New Jersey-Maryland (PJM) Interconnection. In contracts with independent power producers, a demand charge is used to pay for fixed costs and an energy charge (the PJM running rate) is used to pay for variable costs.

## APPROACHES BASED ON MARGINAL COST

### Regional SRMC (for recovery of variable cost)

This approach is similar to the approach based upon the seller's SRMC, except that a single SRMC is computed for all of the sellers in a region. A group of power systems agree to sell power at a price that varies from hour to hour, or at peak and off-peak prices that vary daily. This price is the SRMC of energy from the integrated system, and it is the price charged by all sellers. Those with low variable cost earn high profits while those at the margin earn little profit.

It may be argued that generation costs will be minimized when there is a single regional market in which all prices in the region are based on the regional SRMC. If the marginal resource is made available to all of the potential buyers, the regional SRMC approach should yield more efficient operation than the approach based upon the seller's SRMC. However, power transactions based on a regional SRMC may not be achievable in the Baltic countries because:

- The market for wholesale power in the Baltics is strongly affected by Russia and Belarus, and it would be difficult to negotiate and enforce a regional pricing agreement with these countries.

- The Russian government may artificially reduce its power systems' SRMC by subsidizing the price of fuel used in power generation, and may prohibit power exports based on fuel cost subsidies.

- The potential to minimize generation cost may be only one of the considerations involved in the buyer's selection among sources of supply or the seller's selection among customers; political factors may also be important.

- It may not be possible to collect SRMC data on an hourly basis from all of the power systems, because the communication system is inadequate.

Moreover, the regional SRMC approach has all of the disadvantages listed above for the seller's SRMC approach.

## APPROACHES BASED ON MARGINAL COST

### Regional SRMC (for recovery of fixed and variable cost)

It is possible for a power pool or national grid to establish a method of computing energy charges that is based on the regional SRMC and is intended to provide the seller with enough revenue to recover both fixed and variable costs. This arrangement may be called a "spot pricing pool." There are no capacity charges, but sellers are expected to recover the cost of capacity through revenues based on energy charges (prices per kWh).

In the spot pricing pool in England and Wales, the sellers of power are generating companies. The seller receives two sets of payments:

- the Pool Purchase Price, including
  - the System Marginal Price, which is the regional SRMC of power generation, and
  - an allowance for congestion cost, which equals the Loss of Load Probability multiplied by Value of Lost Load

- the "Uplift," which includes payments for reactive power, out of merit dispatch, lost profits, reserves, and unscheduled available generation

The total of these payments, in theory, can provide generators with an incentive to build new power stations when there is a need to build new power stations. However, generating companies have found it necessary to use hedging contracts to ensure the recovery of their fixed costs. The absence of a guarantee of a "fair" rate of return on invested capital makes the spot pricing pool something innovative and unfamiliar to U.S. utilities. This approach to pricing may be considered experimental. A spot pricing pool does not exist in the United States.

The idea of recovering capital costs through a competitively determined price per kWh may be illustrated by comparing power generation with petroleum refining. A petroleum refinery recovers its capital cost by selling products in spot markets at prices that have no demand charge (or capacity charge). When there is a shortage of refining capacity, refining margins are high enough to attract additional investment; when there is a surplus of refining capacity, refining margins are low enough to discourage additional investment. A company that invests in petroleum refineries must accept this risk.

## APPROACHES BASED ON MARGINAL COST

### Regional SRMC plus capacity charges

In this approach the regional SRMC is used to set an energy charge that is supplemented by capacity charges. The capacity charges are intended to recover capacity costs and other fixed costs, while the energy charges are intended to recover variable costs. The energy charge may vary hourly or daily and the capacity charges may vary monthly or annually.

In the Baltics it may be necessary for a power system to dispatch units for which the cost of generation exceeds the level in neighboring countries such as Russia or Belarus. Thus the average cost of generation (including fixed and variable costs) in a Baltic country may be higher than the regional SRMC for a region including portions of Russia and Belarus. In this situation the regional SRMC may not be high enough cover a portion of capital costs in Estonia, Latvia, or Lithuania. In western countries, however, the average cost of generation is usually lower than the regional SRMC, and a portion of capital cost may be recovered through energy charges based upon the regional SRMC.

In market economies the selection of a methodology to compute capacity charges will depend, in part, on an assessment by regulatory authorities of the effect of these charges on the ability of generating companies or power systems to finance new capacity additions. The usual criterion is that the sum of capacity charge revenue and energy charge revenue should be no higher than the revenue level that is sufficient to finance the capacity additions needed in the region. Capacity additions may be provided by industrial establishments such as cogeneration facilities, as well as new generation companies and power systems.

## Alternative definitions of capacity costs

In most power systems there is a mix of generating units designed for base load, cycling, and peaking, and there is a range of investment alternatives including construction of new generating units, "life extension" of older units, and investment in demand-side management measures (to enable customers to reduce load or shift load from peak to off-peak periods). Capacity may also be purchased from other power systems. Different power systems, regulatory agencies, and experts involved in ratemaking may use different definitions of capacity cost. For example, the following alternatives exist:

A: There are different categories of capacity (at least three categories: baseload, cycling, peaking), and capacity cost can only be defined for a specific category. In a power contract the capacity charge cannot be determined until the load profile is specified or the units needed to provide the power are identified. The capital cost of peaking capacity (in $/kW/year) is usually lower than the price of baseload capacity, because it is cheaper to install a kW of combustion turbine capacity than a kW of baseload power plant capacity. The energy cost of peaking capacity (other than hydro) is usually higher than the baseload energy cost.

B: The cost of a generating unit may be divided into two components: a capacity cost and an investment designed to reduce operating costs. The capacity cost is the cost of the cheapest method of ensuring that the annual peak load can be met - either a new combustion turbine designed for peaking, an increase in hydroelectric peaking capacity, a life extension of an older thermal unit, or a voluntary demand management program. The rest of the capital cost of the generating unit is an investment designed to reduce operating costs.

An investment in generating capacity other than peaking capacity may be justified by projected savings in fuel costs per kWh. For example, it is possible to add a heat recovery steam generator to a combustion turbine to lower fuel costs.

C: The cost of a generating unit may be divided into a capacity cost and an investment designed to reduce operating costs. To simplify the calculation of capacity cost, the capacity cost may be defined as the cost per kW per year of a combustion turbine designed for peaking.

## Alternative methods of computing capacity charges

There are many different ways to compute capacity charges. The following methods are described below:

1) LRMC (based on the cost of peaking capacity)

2) LRMC (based on the cost of the next unit)

3) Seller's distributed cost of capacity, based upon LRMC

4) Seller's incremental capacity cost

5) Buyer's avoided capacity cost

6) Seller's cost at specific generating stations

None of these methods is related to the buyer's ability to pay. In a market economy, electric tariffs are rarely raised to a level at which the customer's ability to pay is an important criterion in selecting a method of computing capacity charges.

In the United States, the buyer's avoided capacity cost is often the basis for capacity charges paid to independent generation companies.

## Alternative methods of computing capacity charges

The LRMC of capacity is the projected cost per kW per year of supplying an additional kW of capacity in a particular portion of the year (for example, the peak hours during the winter season) over a period of many years, using both new and existing plant and equipment and using fuel from the sources of supply that are planned for the future.

This definition may be interpreted in different ways, depending on the approach used to measure capacity cost. The LRMC of capacity may be calculated on the basis of the cost of peaking capacity or the cost of the next generating unit to be built.

LRMC (based on the cost of peaking capacity)

Under Approach C (described above), capacity cost may be defined as the cost per kW per year of a combustion turbine designed for peaking. If this definition of capacity cost is accepted, LRMC must be calculated on the basis of the cost of peaking capacity. This is called the "peaker method" and it is the method that is most commonly used for LRMC analysis. The LRMC (in dollars per kW per year) can be estimated as the projected annual capital cost of a new combustion turbine designed for peaking operation, divided by the capacity of the unit.

Many combustion turbines in the United States are designed to use natural gas during peak periods. The cost of natural gas is typically classified as a "variable cost" although natural gas exploration, production, and transmission are capital-intensive activities with a high proportion of fixed cost. There are two possible approaches to the peaker method:

A: The annual capacity cost associated with a new peaking unit may be defined as the annual cost of the generating unit alone.

B: The annual capacity cost associated with a new peaking unit may be defined as the annual cost of the total capital investment that is (a) necessary to build and operate the unit, and (b) recovered through demand charges or other types of fixed monthly or annual payments. This total capital investment may include investment in gas pipelines, gas storage fields, petroleum product pipelines, and storage tanks for light fuel oil.

## Alternative methods of computing capacity charges

LRMC (based on the cost of the next unit)

One way to implement Approach A - the viewpoint that a particular kind of capacity must be identified before a capacity cost can be measured - is to estimate LRMC based on the cost of the next unit. Under this approach (the "next unit" approach) a least-cost plan is developed for either (a) the power pool or region in which the buyer and seller are located, or (b) the seller's power system alone. To achieve economic efficiency the regional approach is preferred. The capacity cost associated with the next generating unit to be constructed is used to compute the capacity charges in a wholesale power contract.

One reason for considering the "next unit" approach is that the "peaker" approach does not guarantee the seller enough revenue from capacity charges to assure repayment of the cost of a generating unit that has a higher cost per kW than the peaking unit. The "peaker" approach tends to encourage construction of combustion turbines that are expensive to operate and use fuel inefficiently. The "next unit" approach may provide the seller with enough revenue from capacity charges to assure repayment of the capital investment in the next unit or in a comparable type of unit. The "next unit" approach should make it easier for the seller to raise capital.

In a region where none of the power systems are able to build a new generating unit, or the drop in electricity demand has eliminated the need for a new generating unit, the "next unit" approach may not be practical. If the power systems are planning major investments in life extension or demand-side management, the annual capacity cost per kW associated with these investments may be used in place of the annual capacity cost per kW of a generating unit.

### Other approaches to LRMC

There are other approaches to LRMC that are more difficult to implement, and are not included in the list of alternatives in this presentation. For example, the "differential revenue requirements" method involves a comparison between two long-term development plans involving two different projections of electricity demand. It is not always clear how much of the difference in revenue requirements should be allocated to capacity cost; one option is to use the cost of peaking capacity.



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## Alternative methods of computing capacity charges

Seller's distributed cost of capacity, based upon LRMC

Another method of computing capacity charges is to consider wholesale customers to be a class of customers for which prices should be based on the seller's distributed cost. Under this approach the wholesale customer's rates are calculated on the same principles as the household and industrial rates. The capacity charge for wholesale customers is computed on the same principle as the demand charge for large industrial customers.

Among the various methods of allocating capacity costs to customer classes, one alternative is to allocate capacity costs in proportion to the revenue that would be required if capacity were priced at LRMC. This approach involves four steps:

1. The seller computes a total capital carrying charge based on seller's historical cost of plant and equipment. The capital carrying charge includes costs for generation and transmission investment.

2. The seller estimates incremental capacity required to serve each customer class. Incremental capacity is the capacity that would not be needed if the customer class did not have a firm capacity requirement.

3. For each customer class, the cost of incremental capacity is computed on the basis of the LRMC of the incremental capacity required to serve that customer class. An LRMC-based revenue requirement is computed by adding up these costs.

4. The capital carrying charge in step 1 is allocated among customer classes in proportion to their shares of the LRMC-based revenue requirement computed in step 3.



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## Alternative methods of computing capacity charges

Seller's incremental capacity cost

The annual capital cost used to compute capacity charges may be defined as the incremental cost associated with the seller's obligation to provide firm capacity to the buyer. The concept of incremental and decremental cost is routinely applied to variable costs and may also be applied to fixed costs. It is more difficult to apply the concept to fixed costs, however, because it is less clear what the buyer and seller would have done in the absence of the capacity transaction.

The generating capacity that now exists in the Baltic countries was not built for the purpose of implementing contracts to sell capacity. The cost of existing capacity may be considered a "sunk cost" - a capital expenditure that has already been made. The obligation of an importer to pay for this capacity is unclear.

There are two ways to define the seller's incremental capacity cost:

1) The seller's incremental capacity cost is the annual cost per kW that the seller would have avoided if the seller had not had the obligation to provide capacity to the buyer. The seller's obligation may be to provide firm baseload, cycling, or peaking capacity, or some combination of these.

2) The seller's incremental capacity cost is the annual cost that the seller will incur as a result of signing a new contract and making a new commitment to the buyer.



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## Alternative methods of computing capacity charges

Buyer's avoided capacity cost

In the United States the term "avoided cost" is commonly used in negotiations of the price of capacity and energy sold by independent power producers and cogeneration facilities. The concept of avoided cost is very similar to the concept of decremental cost. Avoided costs are projected over the economic life of a new power plant or cogeneration facility.

There are two ways to define the buyer's avoided capacity cost:

1) The buyer's avoided capacity cost is the annual cost per kW that the buyer would have incurred if the buyer had not had the obligation to purchase capacity from the seller.

2) The buyer's avoided capacity cost is the annual cost that the buyer will avoid as a result of signing a new contract and making a new commitment to purchase capacity from the seller.

The buyer's potential savings associated with a contract to purchase capacity and energy involve energy costs as well as capacity costs. However, it would be normal to expect the buyer's avoided capacity cost to be equal to or higher than the seller's incremental capacity cost. If new capacity is involved, the buyer may prefer to determine capacity and energy payments through competitive bidding, rather than basing these payments on the buyer's avoided costs.

## Alternative methods of computing capacity charges

Seller's cost at specific generating stations

It is possible for both capacity and energy charges to be calculated on the basis of the seller's cost at specific generating stations, as described above. Another alternative is to set energy charges on the basis of the regional SRMC and set capacity charges on the basis of the seller's cost at specific generating stations.

Under this approach the seller identifies specific generating stations that can be used to provide firm capacity to the buyer. For each of these stations the seller calculates annual capacity costs per kW on the basis of standard operating assumptions consistent with the design of the plant. For example, the capacity charge could be based upon:

- the stations' annual capital cost per kW, assuming full load
- the station's annual capital cost per kW, based on planned capacity utilization.

This method of computing capacity charges may be preferred to the LRMC-based approaches because it is based upon historical costs incurred by the seller rather than a projection of costs that might be incurred to build generating units in the future. This method is simpler than the distributed cost method because it does not depend on information about the seller's entire power system and projected sales. If a capacity contract does not exist, this method may also be preferred to the seller's incremental cost and buyer's avoided cost approaches, which require a clear definition of the seller's obligation to provide firm capacity to the buyer.

## APPROACHES BASED ON COMPETITIVE BIDDING

### Competitive bidding for energy

Competitive bidding is possible in a situation in which there are only two sellers, but it is preferable to have many sellers - at least five - to discourage collusion and price distortions. Competitive bidding is possible with only one buyer but it works best when there are many buyers and many sellers.

If non-firm energy is being sold, or if there are no capacity contracts among buyers and sellers, it is possible to establish competitive bidding for energy. There are at least two ways to implement competitive bidding for energy:

1. A type of commodity exchange may be set up by a national grid company, power pool, or dispatch center. Prices may be quoted daily for peak and off-peak energy, or may be quoted hourly or even on a half-hour basis. For each time period, buyers and sellers submit bids to the exchange, and transactions can occur as long as the price in a seller's offer is equal to or below the price in a buyer's offer. One alternative is to buy power from the lowest-priced seller first, and buy additional power on the basis of the sellers' offers (taking the lowest-price offer first).

2. A buyer may solicit bids to sell energy on a non-firm basis. If there are no other buyers soliciting bids at the same time, or if the sellers' ability to offer energy to the buyer is totally independent of the sellers' transactions with other buyers, there is no need for a commodity exchange. The buyer can rank the bids according to price and buy the least expensive supplies, until the total amount of energy purchased equals the amount the buyer needs to purchase.

The commodity exchange approach may also be used in situations in which the price per kWh of energy is intended to provide the supplier with enough revenue to cover both fixed costs and variable costs. In England and Wales the generating companies use hedging contracts to stabilize revenues associated with a spot pricing pool.

## APPROACHES BASED ON COMPETITIVE BIDDING

### Competitive bidding for capacity

When new generating units must be constructed, it is possible to determine the level of capacity payments through competitive bidding. This approach is commonly used in the United States by power systems that solicit bids from independent power producers and cogeneration facilities. There are many forms of competitive bidding, but two fundamental types may be distinguished:

1. The buyer may specify not only the amount of capacity needed but also the type of generating unit, the location, and other information needed to develop an accurate engineering cost estimate. The buyer may develop his own cost estimate to determine whether it is better to build and operate the new generating unit or purchase the capacity and energy from an independent generating company.

2. The buyer may specify a certain number of total megawatts of capacity needed, without specifying the type of generating units required. The buyer may specify a set of criteria or a rating system to be used to identify the winning bidder or bidders.

Competitive bidding for capacity is rarely, if ever, used to establish prices for existing capacity.



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## APPROACHES BASED ON PRICES IN OTHER COUNTRIES

### Published prices

The International Energy Agency publishes data on the average price per kWh of electricity sold to households and electricity sold to industry. These prices can be used to establish the level of average revenue per kWh for households and for industry in a formerly socialist economy in which the value of capital assets and the appropriate rate of return on capital are very difficult to measure.

This approach was used in Yugoslavia before the country was divided by civil war. In 1990 Jugel used the average price of electricity sold to industrial customers and to household customers in five countries - Italy, Switzerland, Germany, Austria, and Greece - to set electricity price ceilings in Yugoslavia. The quarterly IEA publication on Energy Prices and Taxes was used as the source of information on price levels.

## APPROACHES BASED ON PRICES IN OTHER COUNTRIES

### Calculations based on generation cost

There are many published reports containing projections of the cost per kWh of power generated from natural gas, heavy fuel oil, coal, and nuclear power. These figures could be used to assign prices to the output of particular generating facilities, or to compute a weighted average price on the basis of the mix of fuels and unit types found in a particular power system.

A recent example of such a report is the International Energy Agency report on Electricity Supply in the OECD (1992).