# Attachment SEB-NSPI-2a

ALABAMA POWER
A SOUTHERN COMPANY

# RATE HLF
# HIGH LOAD FACTOR
# INDUSTRIAL POWER

By order of the Alabama Public Service Commission dated December 7, 1998 in Docket # 24860.

The kWh charges shown reflect adjustment pursuant to Rates RSE and CNP for application to monthly bills effective for April 2006 billings.

| PAGE | EFFECTIVE DATE | REVISION |
|---|---|---|
| 1 of 3 | January, 2006 Billings | Fourteenth |

## AVAILABILITY

Available from the interconnected transmission system of the Company.

## APPLICABILITY

Applicable to high load factor industrial power service requiring 3,000 kW or greater and having a demonstrable annual load factor of approximately ninety percent (90%) or greater. Service shall be taken at one (1) voltage and through a single delivery point. Service to more than one (1) premises shall not be combined. Service shall not be resold or shared with others. The Company reserves the right to negotiate the terms, conditions and arrangements for supplying loads of more than 27,000 kW of capacity subject to the approval of the Alabama Public Service Commission.

## CHARACTER OF SERVICE

Three-phase service directly from the Company's 44 kV or higher transmission system (transmission) or distribution lines (primary). Three phase service at the secondary voltage of transformation facilities supplied from the Company's transmission system (primary) or distribution system (secondary). The Company shall not be required to serve loads of over 20,000 kVa of capacity except from its transmission facilities of 115 kV or higher.

## MONTHLY RATE (TRANSMISSION)

| | |
|---|---|
| Base Charge: | $2,000 per customer; plus |
| Capacity Charge: | $10.00 per kW for all kW of billing capacity; plus |
| Energy Charge: | 0.8595¢ per kWh for all kWh. |

## SEASONAL CAPACITY

Additional capacity, hereinafter referred to as "seasonal capacity," can be supplied on a year-to-year basis during the billing months of October through May provided the Consumer gives a minimum of two months written notice to the Company each year seasonal capacity is desired and the Company determines it has sufficient seasonal capacity available. In case of a system emergency, the Company may temporarily suspend the delivery of seasonal capacity. The Company shall not be required to furnish additional facilities to supply seasonal capacity.

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|---|---|---|
| 2 of 3 | January, 2006 Billings | Fourteenth |

## DETERMINATION OF BILLING CAPACITY

The capacity for billing purposes shall be the maximum integrated fifteen (15) minute capacity during each billing period of approximately thirty (30) days, measured in kilowatts by an appropriate capacity meter; provided, however, that such capacity shall be no less than ninety percent (90%) of the measured maximum capacity requirements established during the previous eleven (11) months (except for months in which seasonal capacity is requested, made available and utilized) or less than ninety percent (90%) of the contracted capacity or 3,000 kW, whichever is greatest.

## ADJUSTMENT FOR TRANSFORMATION FACILITIES

Monthly charges shall be increased by seventy-six cents (76¢) per kW of billing capacity whenever the Company supplies transformation facilities from its transmission lines. The monthly charges shall be increased by one dollar and thirty cents ($1.30) per kW of billing capacity whenever the Company supplies transformation facilities from its distribution lines.

## ADJUSTMENT FOR LOW POWER FACTOR

The bill calculated at the above rates shall be increased in the amount of thirty cents (30¢) per month per kVa of capacity requirements in excess of the kVa of capacity corresponding to a power factor of ninety percent (90%). The excess of kVa to which such charge applied shall be determined by dividing the maximum kW capacity recorded in the current billing month by 0.90 and subtracting the results from the kVa capacity requirements at the time of occurrence of such maximum kW capacity.

## MINIMUM BILL

No monthly bill will be rendered for less than the Base Charge, plus the capacity charge, plus applicable adjustments for transformation, plus applicable provisions of Rate ECR (Energy Cost Recovery) and Rate T (Tax Adjustment).

## PAYMENT

Bills for service rendered hereunder are payable within ten (10) days from the due date and if not paid within such period become delinquent and subject to charges as set forth in the Company's Rules and Regulations.

ALABAMA POWER
A SOUTHERN COMPANY

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|---|---|---|
| 3 of 3 | January, 2006 Billings | Fourteenth |

## TERM OF CONTRACT

Service under this rate shall be for a minimum period of ten (10) years for new Consumers (initial service or any major addition thereto) and not less than one (1) year for other Consumers. After the initial term (whichever is applicable), service hereunder shall continue until terminated by one (1) year written notice by either party to the other.

## ENERGY COST RECOVERY

The amount calculated at the above rate will be increased under the provisions of the Company's Rate ECR (Energy Cost Recovery) by applying the effective Energy Cost Recovery Factor.

## RATE STABILIZATION AND EQUALIZATION

Rate RSE (Rate Stabilization and Equalization Factor) is incorporated in this rate and will be applied to adjust (increase or decrease) kWh charges calculated hereunder.

## ADJUSTMENT FOR COMMERCIAL OPERATION OF CERTIFICATED NEW PLANT

Rate CNP (Adjustment for Commercial Operation of Certificated New Plant) is incorporated in this rate and will be applied to increase kWh charges calculated hereunder.

## NATURAL DISASTER RESERVE

The amount calculated at the above rate will be increased under the provisions of the Company's Rate Rider NDR (Natural Disaster Reserve) by applying the effective NDR Charge.

## GENERAL

The amount calculated at the above rate is subject to possible tax adjustments as set forth in Rate T (Tax Adjustment) and to rules and regulations approved or prescribed by the Alabama Public Service Commission, including any Special Rules and Regulations governing the application of this rate.

ALABAMA POWER
A SOUTHERN COMPANY

# NON-FIRM CAPACITY INTERRUPTIBLE CREDIT

By order of the Alabama Public Service Commission Dockets #18117 and #18416.

| PAGE | EFFECTIVE DATE | REVISION |
|---|---|---|
| 1 of 1 | December 1, 1982 Billings | Original |

## ANNUAL CREDIT

$30.60 per KW per Year

$27.60 per KVA per Year

# ALABAMA POWER COMPANY
# BILL CALCULATION FACTORS
# 2006

| Month | NDR Res / Comm | ECR FACTOR (Mills per KWH) | | | | | ITA FACTOR % |
|---|---|---|---|---|---|---|---|
| | | ACTUAL FACTOR | SEC. | PRI. | SUB. | TRAN. | |
| January | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.882 |
| February | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.784 |
| March | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.784 |
| April | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.784 |
| May | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.655 |
| June | 2.48 / 6.15 | 24.000 | 26.578 | 25.068 | - | 24.418 | -2.655 |
| July | 2.48 / 6.15 | 24.000 | 26.578 | 25.068 | - | 24.418 | -2.655 |
| August | 2.48 / 6.15 | 24.000 | 26.578 | 25.068 | - | 24.418 | -2.517 |
| September | 2.48 / 6.15 | 24.000 | 26.578 | 25.068 | - | 24.418 | -2.517 |
| October | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.517 |
| November | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.430 |
| December | 2.48 / 6.15 | 24.000 | 23.439 | 22.108 | - | 21.534 | -2.430 |

Avg. = 22.255

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE

*Rate Based on Monthly Meter Readings

Summer Rate (Applicable during 4 monthly billing periods of June through September)

| | | Effective | |
|---|---|---|---|
| | 4/1/02 | 4/1/03 | 4/1/04 |
| Customer Charge - per month | $210.00 | $210.00 | $210.00 |
| Energy Charge - per kWh | 2.51¢ | 2.42¢ | 2.34¢ |
| Demand Charge - per kW of Billing Demand | $14.99 | $14.48 | $13.97 |
| Reactive Charge - per kVar | 24.00¢ | 24.00¢ | 24.00¢ |

Winter Rate (Applicable during 8 monthly billing periods of October through May)

| | | Effective | |
|---|---|---|---|
| | 4/1/02 | 4/1/03 | 4/1/04 |
| Customer Charge - per month | $210.00 | $210.00 | $210.00 |
| Energy Charge - per kWh | 2.21¢ | 2.13¢ | 2.06¢ |
| Demand Charge - per kW of Billing Demand | $6.80 | $6.57 | $6.34 |
| Reactive Charge - per kVar | 24.00¢ | 24.00¢ | 24.00¢ |

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $14.00 per month

| Energy Adjustment - per kWh | On-Peak Hours(1) | Off-Peak Hours(1) |
|---|---|---|
| Summer kWh(June-September billing periods) | +0.45¢ | -0.25¢ |
| Winter kWh(October-May billing periods) | +0.20¢ | -0.11¢ |

(1) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

Payments. Bills are due and payable within ten (10) days from date of bill.

Term of Use. One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

*Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE (CONT'D.)

1. Rate Application. The rate shall be applicable, at customer's request, to all service at a primary voltage or higher, provided customer agrees to a minimum monthly billing demand of 5000 kilowatts.

*2. Character of Service Supplied. Company will specify and supply a standard three-phase alternating current primary service voltage. Where Company supplies service at 34.5 kV or higher, the appropriate adjustments under Rider B will apply.

3. Cumulation of Services. Service provided through multiple meters to the same customer on the same premises and cumulated for billing purposes under this Service Classification, prior to May 5, 1990, may continue to receive such billing. Unless otherwise required for Company's engineering or other reasons, any additional services installed at customer's request and agreed to by Company on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

4. Demand Meters. Company will install demand meters for the measurement of demands.

5. Billing Demand. The billing demand in any month will be the highest demand established during peak hours or 50% of the highest demand established during off-peak hours, whichever is highest during the month, but in no event less than 5000 kW.

Peak hours and off-peak hours are defined as follows:

Peak hours: 10:00 A.M. to 10:00 P.M., Monday thru Friday.

Off-peak hours: All other hours including the entire 24 hours of the following days:

| | | |
|---|---|---|
| New Year's Day | Independence Day | Thanksgiving Friday |
| Good Friday | Labor Day | Christmas Eve Day |
| Memorial Day | Thanksgiving Day | Christmas Day |

All times stated above apply to the local effective time.

*Indicates Reissue.

Issued pursuant to the Order of the Mo.P.S.C. in Case No. ED-91-122.

P.S.C. Mo. DATE OF ISSUE March 7, 1994 DATE EFFECTIVE April 6, 1994

ILL. C.C. DATE OF ISSUE _____ DATE EFFECTIVE _____

IA.ST.C.C. DATE OF ISSUE _____ DATE EFFECTIVE _____

ISSUED BY Charles W. Mueller (NAME OF OFFICER) President & CEO (TITLE) St. Louis, Missouri (ADDRESS)

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE (Cont'd.)

6. Reactive Charge. The charge specified in this rate shall be applicable to the kilovars by which the customer's average metered kilovars exceed the customer's kilovars at an average power factor of 90% lagging during the billing period. Such average kilovar billing units shall be determined in accordance with the following formula:

$$kVar = \left(\frac{kVarh}{kWh} - 0.4843\right)(kW)$$

where:

| | | |
|---|---|---|
| kVar | = | kilovar billing units |
| kVarh | = | metered kilovarhours |
| kWh | = | metered kilowatthours |
| kW | = | metered kilowatts |
| 0.4843 | = | kilovar requirement at 90% lagging power factor. |

Where in the Company's judgement application of the above formula would not be appropriate to full or partial self-generation customers, an alternative agreement, between Company and customers, for the payment of reactive supply facilities may be substituted for said formula.

*7. Optional Time-of-Day (TOD) Service. Applicable at customer's option for all Large Primary Service usage, subject to the following provisions:

A. Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

B. Customer electing this TOD option, shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

C. Any customer canceling this TOD option cannot thereafter resume billing under said option for a period of one year following the last billing period on the TOD option.

8. General Rules and Regulations. In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

*Indicates Addition.

Rider B

DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP

*A. Where a substation provided or leased by Customer transforms all or a part of the service from a delivery voltage of 34,500 volts or higher to a lower voltage, the Company will adjust meter readings and allow discounts from its applicable rate schedule as follows:

| Delivery Voltage | Metering Level | Meter Adjustment | Billing KW Discount (1) |
|---|---|---|---|
| 138,000 Volts or Higher | 138,000 Volts or Higher | See Rider C | $0.95/kW |
| 138,000 Volts or Higher | Primary Voltage | None | $0.95/kW |
| 34,500 or 69,000 Volts | 34,500 Volts or Higher | See Rider C | $0.81/kW |
| 34,500 or 69,000 Volts | Primary Voltage | None | $0.81/kW |

(1) Per kW of billing demand.

*Indicates Change.

VA. S.C.C. TARIFF NO. 19

SCHEDULE L.P.S.-T.O.D.
(Large Power Service Time-of-Day)

## AVAILABILITY OF SERVICE

Available for electric service to general service customers with normal maximum electrical capacity requirements greater than 1,000 KW who take Standard Service from the Company. Each customer shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet the customer's normal maximum requirements for the on-peak period and a definite amount of electrical capacity in kilowatts which shall be sufficient to meet normal maximum requirements for the off-peak period, but in no case shall the capacity contracted for be less than 1,000 KW. When a customer being served under this Schedule establishes metered demands less than 1,000 KW per month for ten (10) or more months during the past twelve (12) months, the customer will be placed on the appropriate general service Standard Schedule. The Company shall not be required to supply capacity in excess of the on-peak and off-peak capacities for which the customer has contracted. Contracts shall be in multiples of 100 KW.

## MONTHLY RATE

| Schedule Code | | Generation | OATT Transmission | Retail Transmission | Distribution | Total |
|---|---|---|---|---|---|---|
| 302 | **Secondary Voltage:** | | | | | |
| | Customer Charge ($) | -- | -- | -- | 320.00 | 320.00 |
| | Demand Charge ($/KW) | 8.74 | 1.66 | 0.04 | 3.98 | 14.42 |
| | Off-Peak Excess Demand Charge ($/KW) | 1.11 | -- | 0.04 | 3.98 | 5.13 |
| | Energy Charge (¢/KWH) | 0.445 | -- | -- | -- | 0.445 |
| 306 | **Primary Voltage:** | | | | | |
| | Customer Charge ($) | -- | -- | -- | 380.00 | 380.00 |
| | Demand Charge ($/KW) | 8.48 | 1.61 | 0.04 | 2.16 | 12.29 |
| | Off-Peak Excess Demand Charge ($/KW) | 1.14 | -- | 0.04 | 2.16 | 3.34 |
| | Energy Charge (¢/KWH) | 0.433 | -- | -- | -- | 0.433 |
| 308 | **Subtransmission Voltage:** | | | | | |
| | Customer Charge ($) | -- | -- | -- | 460.00 | 460.00 |
| | Demand Charge ($/KW) | 7.89 | 1.57 | 0.04 | 0.00 | 9.50 |
| | Off-Peak Excess Demand Charge ($/KW) | 0.91 | -- | 0.04 | 0.00 | 0.95 |
| | Energy Charge (¢/KWH) | 0.424 | -- | -- | -- | 0.424 |

VA. S.C.C. TARIFF NO. 19

**SCHEDULE L.P.S.-T.O.D.**
**(Large Power Service Time-of-Day)**
**(continued)**

**MONTHLY RATE** (Cont'd)

| Schedule Code | | Generation | OATT Transmission | Retail Transmission | Distribution | Total |
|---|---|---|---|---|---|---|
| 310 | **Transmission Voltage:** | | | | | |
| | Customer Charge ($) | -- | -- | -- | 575.00 | 575.00 |
| | Demand Charge ($/KW) | 7.07 | 1.55 | 0.04 | 0.00 | 8.66 |
| | Off-Peak Excess Demand Charge ($/KW) | 0.83 | -- | 0.04 | 0.00 | 0.87 |
| | Energy Charge (¢/KWH) | 0.419 | -- | -- | -- | 0.419 |

Distribution Reactive Demand Charge for each KVAR of leading or lagging reactive demand in excess of 50% of the KW metered demand ..... $0.75 per KVAR

Generation Levelized Fuel Factor ..... 1.785¢ per KWH

**MINIMUM CHARGE**

This Schedule is subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

**CUSTOMER-OWNED METERS**

Customers taking service under this schedule have the option of owning their electric service meter. Customer-owned meters shall be consistent with the Company's billing and metering systems and communication protocol, including all of the Company's requirements for the recording and communication of appropriate usage and interval data. In addition, customers are responsible for the cost of any replacement or updating of their metering that may become necessary from time to time as a result of changes to these systems and protocol. All customer-owned meters must remain in sound condition and good working order. The Company shall continue to designate the location of all meters.

Customers must make a request to the Company to own their electric service meter. Upon approval, the Company will remove the Company's meter and install and maintain the customer-owned meter. Company maintenance shall be limited to periodic testing, standard programming and temporary replacement of meters found to be defective or otherwise in need of repair or refurbishment. Customer-owned meters found to be defective will be returned to the customer and temporarily replaced with a Company-owned meter until such time that a repaired or replacement customer-owned meter is provided to the Company for installation. Any other services related to the customer-owned meter will be provided at the Company's sole discretion.

The customer's delivery point, as specified in the Company's Terms and Conditions of Standard Service, is unchanged by customer ownership of the meter, except that such meter becomes part of the customer's facilities and equipment. All liability for loss, injury or damage caused by the customer-owned meter shall be the responsibility of the customer. The Company retains all of its rights to disconnect the meter, regardless of meter ownership.

The Company shall have full access to the meter for reading and maintenance. The customer shall have read-only access to the meter and, at the sole discretion of the Company, if available, limited programming access. The customer shall have no other access to the meter while it is installed.

The customer shall be responsible for all Company-incurred costs associated with the customer-owned meter. Such costs include, but are not necessarily limited to, the initial removal of the Company-owned meter, installation and set-up of the customer-owned meter and any subsequent temporary replacement of the electric service meter as described herein. In the event that a customer-owned meter is installed at a service location where no Company-owned meter is present, in addition to any applicable service connection or reconnection charges, the customer shall be responsible for the incremental cost of installing the customer-owned meter over and above the cost of installing a Company-owned meter. The customer shall also be responsible for the total Company-incurred cost of all testing of the meter and any related communication equipment, whether such testing is initiated by the Company or at the customer's request. All such charges will be billed directly to the customer by the Company.

VA. S.C.C. TARIFF NO. 19

**SCHEDULE L.P.S.-T.O.D.**
**(Large Power Service Time-of-Day)**
**(continued)**

**CUSTOMER-OWNED METERS (Cont'd)**

The customer will receive a credit for each entire billing month in which the customer-owned meter is installed and functioning at the customer's service location. The credit shall be the following:

| | Delivery Voltage | | | |
|---|---|---|---|---|
| | Secondary | Primary | Subtransmission | Transmission |
| Credit ($/month) | 0.98 | 0.98 | 0.98 | 4.09 |

Customers may, at any time upon request to the Company, discontinue ownership of the electric service meter. Upon such a request, the Company will replace the customer-owned meter with a Company-owned meter and charge the customer for the cost of such replacement. The Company will subsequently provide all metering services, and the customer shall no longer receive the monthly metering credit.

Customers who notify the Company of their intention to discontinue service under this schedule shall be responsible for the cost of removing the customer-owned meter and installing a Company-owned meter. However, such customers who are moving to another schedule of the Company that provides for customer-owned metering shall be responsible for only the cost of any required metering changes.

**PAYMENT**

Bills are due upon presentation. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company within twenty (20) days of the bill preparation date shall be subject to a delayed payment charge of 1½%. This charge shall not be applicable to local consumer utility taxes.

**MEASUREMENT AND DETERMINATION OF BILLING DEMAND**

The billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's on-peak contract capacity, or (b) the customer's highest previously established monthly billing demand during the past 11 months.

The off-peak billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the off-peak period by a demand meter or indicator. The monthly off-peak billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's off-peak contract capacity or (b) the customer's highest previously established off-peak monthly billing demand during the past 11 months.

The off-peak excess demand shall be the amount by which the monthly off-peak billing demand exceeds the monthly billing demand.

The reactive demand in KVAR shall be taken each month as the single highest 30-minute peak in KVAR as registered during the month by a demand meter or indicator.

Billing demands shall be rounded to the nearest whole KW and KVAR.

For the purpose of this Schedule, the on-peak billing period is defined as 7 a.m. to 8 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 8 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

VA. S.C.C. TARIFF NO. 18

**SCHEDULE L.P.S.-T.O.D.**
**(Large Power Service Time-of-Day)**
**(continued)**

**CUSTOMER-OWNED METERS (Cont'd)**

Customers may, at any time upon request to the Company, discontinue ownership of the electric service meter. Upon such a request, the Company will replace the Customer-owned meter with a Company-owned meter and charge the customer for the cost of such replacement. The Company will subsequently provide all metering services, and the customer shall no longer receive the monthly metering credit.

Customers who notify the Company of their intention to discontinue service under this schedule shall be responsible for the cost of removing the customer-owned meter and installing a Company-owned meter. However, such customers who are moving to another schedule of the Company that provides for customer-owned metering shall be responsible for only the cost of any required metering changes.

**PAYMENT**

Bills are due upon presentation. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company within twenty (20) days of the bill preparation date shall be subject to a delayed payment charge of 1½%. This charge shall not be applicable to local consumer utility taxes.

**MEASUREMENT AND DETERMINATION OF BILLING DEMAND**

The billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's on-peak contract capacity, or (b) the customer's highest previously established monthly billing demand during the past 11 months.

The off-peak billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the off-peak period by a demand meter or indicator. The monthly off-peak billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's off-peak contract capacity or (b) the customer's highest previously established off-peak monthly billing demand during the past 11 months.

The off-peak excess demand shall be the amount by which the monthly off-peak billing demand exceeds the monthly billing demand.

The reactive demand in KVAR shall be taken each month as the single highest 30-minute peak in KVAR as registered during the month by a demand meter or indicator.

Billing demands shall be rounded to the nearest whole KW and KVAR.

For the purpose of this Schedule, the on-peak billing period is defined as 7 a.m. to 8 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 8 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

**METERED VOLTAGE ADJUSTMENT**

The rates set forth in this Schedule are based upon the delivery and measurement of energy at the same voltage. When the measurement of energy occurs at a voltage different than the delivery voltage, the measurement of energy will be compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses, or the application of multipliers to the metered quantities. In such cases, metered KWH, KW and KVAR will be adjusted for billing purposes. In cases where multipliers are used to adjust metered usage, the adjustment shall be as follows:

(a) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.
(b) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

VA. S.C.C. TARIFF NO. 18

**SCHEDULE L.P.S.-T.O.D.**
**(Large Power Service Time-of-Day)**
**(continued)**

## EQUIPMENT SUPPLIED BY CUSTOMER

Customers who as of October 7, 1983, owned, operated and maintained all equipment and apparatus beyond the delivery point of service, were receiving equipment credit for such ownership, and whose service was supplied at a delivery voltage of 34,500 volts (primary delivery voltage) shall receive a retail transmission credit of $0.54 per KW for the sum of the on-peak and off-peak excess monthly billing demands. Such credit shall apply only to customers billed under the primary delivery voltage rates of this Schedule.

## TERM

Contracts will be required for an initial period of not less than two (2) years and shall remain in effect thereafter until either party shall give the other at least twelve (12) months' written notice of the intention to discontinue service under this Schedule.

A new initial contract will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. The Company reserves the right to make initial contracts for periods longer than two (2) years.

Customers may change from the Standard Schedule L.P.S. to the corresponding Open Access Distribution Schedule O.A.D.-L.P.S. as specified in the Company's Terms and Conditions of Standard Service.

Except in instances where the Company has significant investment in local facilities or other special agreements with the customer, qualifying customers may elect to take service from a qualified Energy Service Provider pursuant to the terms and conditions of the applicable Open Access Distribution Schedule as specified in the Use of Energy by Customer provision of the Company's Terms and Conditions of Standard Service.

## SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Standard Service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company. All other customers having sources of electrical energy supply other than the Company shall take service under Schedule S.B.S.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

# SCHEDULE I.P.
(Industrial Power Service)

## AVAILABILITY OF SERVICE

(C) Available for general service to customers. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet maximum requirements, but in no case shall the contract capacity be less than 1,000 KW.

## MONTHLY RATE

| Schedule Codes | Service Voltage | Demand Charge ($/KW) | Off-Peak Excess Demand Charge ($/KW) | Energy Charge (¢/KWH) | Customer Charge ($/Month) |
|---|---|---|---|---|---|
| 327 | Secondary | (D) 12.33 | (I) 6.05 | (I) 1.813 | (I) 85.00 |
| 322 | Primary | (D) 11.06 | (I) 3.95 | (I) 1.760 | 275.00 |
| 323 | Subtransmission | (D) 9.18 | (I) 1.56 | (I) 1.673 | (I) 375.00 |
| 324 | Transmission | (D) 8.55 | (I) 1.47 | (I) 1.646 | (I) 475.00 |

Reactive Demand Charge for each KVAR of leading or lagging reactive demand in excess of 50% of the KW metered demand ..... $0.62/KVAR

## MINIMUM CHARGE

This Schedule is subject to a minimum monthly charge equal to the sum of the Customer Charge, the product of the Demand Charge and the monthly billing demand, and all applicable adjustments.

## LOCAL TAX ADJUSTMENT

(C) To bills for electric service supplied within specified municipalities or political subdivisions which impose taxes based upon the amount of electric service sold or revenues received by the Company, as specified on Original Sheet No. 4-1, will be added a surcharge equal to the percentage shown on Sheet Nos. 4-2, 4-3, and 4-4 to accomplish a recovery of these taxes.

(O)

## PAYMENT

Bills are due upon receipt. Any amount due and not received by mail, checkless payment plan, electronic payment plan, or at authorized payment agents of the Company by the "Last Pay Date" shown on the bill shall be subject to a delayed payment charge of 1%. This charge shall not be applicable to local consumer utility taxes.

## MEASUREMENT AND DETERMINATION OF DEMAND AND ENERGY

The billing demand in KW shall be taken each month as the single highest 30-minute peak in KW as registered during the month in the on-peak period by a demand meter or indicator. The monthly billing demand established hereunder shall not be less than 60% of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE I.P.
(Industrial Power Service)
(continued)

**MEASUREMENT AND DETERMINATION OF DEMAND AND ENERGY** (Cont'd)

The off-peak excess demand shall be the amount by which the demand created during the off-peak period exceeds the monthly billing demand.

The reactive demand in KVAR shall be taken each month as the highest single 30-minute peak in KVAR as registered during the month by a demand meter or indicator.

Billing demands shall be rounded to the nearest whole KW and KVAR.

For the purpose of this Schedule, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, for all weekdays, Monday through Friday. The off-peak billing period is defined as 9 p.m. to 7 a.m., local time, for all weekdays, all hours of the day on Saturdays and Sundays, and the legally observed holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

**METERED VOLTAGE ADJUSTMENT**

The rates set forth in this Schedule are based upon delivery and measurement of energy at the same voltage. When the measurement of energy occurs at a voltage different than the delivery voltage, the measurement of energy will be compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment or the application of multipliers to the metered quantities. In such cases, metered KWH, KW and KVAR will be adjusted for billing purposes. In cases where multipliers are used to adjust metered usage, the adjustment shall be as follows:

(a) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(b) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

**TERM**

The customer shall contract for a definite amount of electrical capacity in kilowatts which shall be sufficient to meet maximum requirements, but in no event shall the contract capacity be less than 1,000 KW.

Contracts will be required for an initial period of not less than two (2) years and shall remain in effect thereafter until either party shall give the other at least one (1) year's written notice of the intention to discontinue service under this Schedule.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required. The Company reserves the right to make initial contracts for periods longer than two (2) years pursuant to the Extension of Service provision of the Company's Terms and Conditions of Service.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

P.S.C. W.VA. TARIFF NO. 12 (APPALACHIAN POWER COMPANY)
P.S.C. W.VA. TARIFF NO. 17 (WHEELING POWER COMPANY)

SCHEDULE I.P.

(Industrial Power Service)
(continued)

SPECIAL TERMS AND CONDITIONS

This Schedule is subject to the Company's Terms and Conditions of Service.

Customers with cogeneration and/or small power production facilities shall take service under Schedule COGEN/SPP or by special agreement with the Company.

**Aquila, Inc., dba**
**AQUILA NETWORKS**
**KANSAS CITY, MO 64138**

For Territory Served by Aquila Networks – L&P

# LARGE POWER SERVICE
# ELECTRIC

## AVAILABILITY

Available for combined lighting and power service to any customer who shall contract for a minimum capacity of five hundred (500) kilowatts (kW) for a period of twelve (12) consecutive months.

## BASE RATE, MO944

Facilities kW Charge
- For the first five hundred (500) Facilities kW, per bill ..... $678.40
- For all over five hundred (500) Facilities kW, per each Facilities kW ..... $1.06

Billed Demand Charge
- Billing cycles June through September
  - for each kW ..... $7.77
- Billing cycles October through May
  - for each kW less than or equal to Previous Summer Peak kW ..... $3.32
  - for each kW over Previous Summer Peak kW ..... $.21

Energy Charge per kWh
- Billing cycles June through September
  - for each "on-peak" kWh ..... $.0360
  - for each "off-peak" kWh ..... $.0254
- Billing cycles October through May
  - for each "on-peak" kWh ..... $.0296
  - for each "off-peak" kWh ..... $.0223

## LATE PAYMENT CHARGE

See Company Rules and Regulations

## DEMAND DETERMINATIONS:

### Facilities kW

The Facilities kW shall be determined by a comparison of the Actual kW in the current billing period and the Actual kW as recorded in each of the previous eleven (11) billing periods. If there are less than eleven (11) previous billing periods, the determination will be made using all available previous billing periods. The Facilities kW is defined as the maximum Actual kW as determined from the comparison but in no case less than five hundred (500) kW for Facilities kW Charge billing purposes.

*As an example, if the current billing period's Actual kW is one thousand (1,000) kW and the single highest Actual kW recorded in any of the previous eleven (11) billing periods is one thousand two hundred (1,200) kW, then the facilities KW to be used in the current billing would be one thousand two hundred (1,200) kW. The Facilities kW Charge would be $678.40 +((1200 - 500) * $1.06) = $1,420.40 for the current billing period.*



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LARGE POWER SERVICE (Continued)
ELECTRIC

Billed Demand

The Billed Demand shall be the greater of:

1) the maximum fifteen (15) minute "on-peak" demand measured during the current billing period,

or

2) fifty percent (50%) of the maximum fifteen (15) minute "off-peak" demand measured during the current billing period.

The Billed Demand in no case shall be less than five hundred (500) kW.

Previous Summer Peak kW

The Previous Summer Peak kW shall be the greater of:

1) the maximum fifteen (15) minute "on-peak" demand measured during the most recent billing months of July, August, and September

or

2) fifty percent (50%) of the maximum fifteen (15) minute "off-peak" demand measured during the most recent billing months of July, August, and September.

The Previous Summer Peak kW in no case shall be less than five hundred (500) kW.

The Previous Summer Peak kW, once established, shall be used for the billing periods of October through May immediately following the most recent summer period.

BILLING PERIODS

| | Summer | | Winter | |
|---|---|---|---|---|
| Weekdays (except holidays) | | | | |
| On-peak | 10 a.m. - 10 p.m. | 12 hrs x 5 days = 60 hrs per week | 7 a.m. - 10 p.m. | 15 hrs/day x 5 = 75 hrs/week |
| Off-peak | 10 p.m. - 10 a.m. | | 10 p.m. - 7 a.m. | |
| Weekends, holidays | | | | |
| Off-peak | all hours | = 36% | all hours | = 45% |

All times listed are Central Standard Time or, when in effect, Central Daylight Savings Time. Holidays are defined as New Year's Day, Memorial Day observed, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

SPECIAL RULES

The voltage, frequency, and phase of all service under this schedule shall be only as specified by the Company.

Service will be furnished under, and this schedule shall be subject to Company Rules and Regulations.

Service is furnished for the sole use of the customer on the premises described in the service application. There shall be no resale or submetering of energy.



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LARGE POWER SERVICE (Continued)
ELECTRIC

SPECIAL RULES (Continued)

Where transformers are required for individual customers under this schedule, the customer may be required to provide satisfactory space and access on his premises for such transformers.

The above rate or minimum bill does not include any franchise or occupations tax. The Company Tax and License Rider is applicable to all charges under this schedule.

METERING LOSS ADJUSTMENT

Where service is metered at a voltage level other than secondary, an adjustment to both the kilowatt-hour (kWh) and kilowatt (kW) readings will be made as follows:

1. Service Metered at Primary Voltage
   Where service is provided directly from a twelve (12) kV circuit feeder and is metered at four (4) kV or twelve (12) kV, the metered kWh and kW will be reduced by one and one-half percent (1.5%).

2. Service Metered at Substation Voltage
   Where service is metered at four (4) kV or twelve (12) kV directly from a substation, the metered kWh and kW will be reduced by two and one-half percent (2.5%).

3. Service Metered at Transmission Voltage
   Where service is metered at thirty-four (34) kV and above directly from a transmission line, the metered kWh and kW will be reduced by three percent (3%).

If the customer's meter has to be relocated in order for the customer to become eligible for the metering loss adjustment, all costs associated with the relocation shall be paid by the customer.

This adjustment only applies to customers served at secondary voltage.
This Metering Loss Adjustment is not available for new installations after March 1, 2006.

WEB USAGE SERVICE

Customers served under this LPS rate schedule are eligible for basic monthly web usage service which includes web access to their usage for fifteen (15) minute interval data which is updated once per month.



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**Aquila, Inc., dba**
**AQUILA NETWORKS**
**KANSAS CITY, MO 64138**

For Territory Served by Aquila Networks – L&P

# PRIMARY DISCOUNT RIDER
# ELECTRIC

## AVAILABILITY

Available to customers served under rate schedules MO940 or MO944 who receive three-phase alternating-current electric service at a primary voltage level and who provide and maintain all necessary transformation and distribution equipment beyond the point of Company metering.

## PRIMARY KW DISCOUNT

for each Primary kW ..... $(0.59)

## DETERMINATION OF PRIMARY KW

The Primary kW shall be the highest fifteen (15) minute actual demand, measured during the current billing period and the previous eleven (11) billing periods. The Primary kW, once established, shall be used for a period of twelve (12) consecutive billing periods unless a greater Primary kW is established.



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AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 25

EXTRA LARGE GENERAL SERVICE - IDAHO
(Three phase, available voltage)

AVAILABLE:

To Customers in the State of Idaho where Company has electric service available.

APPLICABLE:

To general service supplied for all power requirements when all such service taken on the premises is supplied through one meter installation for a demand of not less than 2,500 kVA but not greater than 25,000 kVA. The average of the Customer's demand for the most recent twelve-month period must fall within these demand limits for service under this schedule. If the Customer has less than twelve months of billing history, the Customer must have a minimum of six consecutive billing months of demand of at least 2,500 kVA in order to receive service under this schedule. New Customers must meet the above criteria or otherwise provide the Company with reasonable assurance that their peak demand will average at least 2,500 kVA. Customer shall provide and maintain all transformers and other necessary equipment on his side of the point of delivery and enter into a written contract for five (5) years or longer.

MONTHLY RATE: The sum of the following demand and energy charges:

Energy Charge:

| | | |
|---|---|---|
| First | 500,000 kWh | 3.942¢ per kWh |
| All Over | 500,000 kWh | 3.339¢ per kWh |

Demand Charge:

$9,000.00 for the first 3,000 kVA of demand or less.
$2.75 per kVA for each additional kVA of demand.

Primary Voltage Discount:

If Customer takes service at 11 kV (wye grounded) or higher, he will be allowed a primary voltage discount of 20¢ per kVA of demand per month.

Minimum:

The demand charge unless a higher minimum is required under contract to cover special conditions.

ANNUAL MINIMUM: $511,470

Any annual minimum deficiency will be determined during the April billing cycle for the previous 12-month period. For a customer who has taken service on this schedule for less than 12 months, the annual minimum will be prorated based on the actual months of service.

AVISTA CORPORATION
dba Avista Utilities

SCHEDULE 25A

DEMAND:

The average kVA supplied during the 30-minute period of maximum use during the current month as measured by Company's metering equipment.

SPECIAL TERMS AND CONDITIONS:

For Customers who have more than one metering point to serve contiguous facilities or properties, the coincident demand from all such meters must not exceed 25,000 kVA in order to receive service under this schedule. Customers whose demand from all such meters exceeds 25,000 kVA may be served under special contract wherein the rates, terms, and conditions of service are specified and approved by the I.P.U.C. If the Company and the Customer cannot agree on the rates, terms, and conditions of service, the matter will be brought before the I.P.U.C. for resolution. If the Customer requires service during either the contract negotiation or resolution period, service will be supplied under this rate schedule subject to refund or surcharge based on the terms of the final contract.

For Customers whose power factor is less than 80%, their kVA demand will be computed at an 80% power factor and the resulting kVA must be at least 2,500 in order to receive service under this schedule.

Customers utilizing resistance load banks solely for the purpose of increasing their demand in order to qualify for service under this schedule will not be served under this schedule.

Existing Customers who install demand-side management measures after May 1, 1992, which cause their demand to fall below 2,500 kVA will continue to qualify for service under this schedule. The Company will estimate the Customer's demand reduction created by those demand-side management measures in order to determine qualification for service under this schedule. If a Customer installs demand-side management measures without assistance from the Company, it is the Customer's responsibility to inform the Company regarding the installation of such measures.

Service under this schedule is subject to the Rules and Regulations contained in this tariff.

The above Monthly Rates are subject to increases or decreases as set forth in Tax Adjustment Schedule 58, Temporary Rate Adjustment Schedule 65, Temporary Power Cost Adjustment Schedule 66, and Energy Efficiency Rider Adjustment Schedule 91.

AVISTA CORPORATION
d/b/a Avista Utilities

SCHEDULE 66

TEMPORARY POWER COST ADJUSTMENT - IDAHO

APPLICABLE:

To Customers in the State of Idaho where the Company has electric service available. This Power Cost Adjustment shall be applicable to all retail customers for charges for electric energy sold and to the flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service. This Rate Adjustment is designed to recover or rebate a portion of the difference between actual and allowed net power supply costs.

MONTHLY RATE:

The energy charges of the individual rate schedules are to be increased by the following amounts:

| | |
|---|---|
| Schedule 1 | 0.163¢ per kwh |
| Schedules 11 & 12 | 0.190¢ per kwh |
| Schedules 21 & 22 | 0.145¢ per kwh |
| Schedules 25 | 0.103¢ per kwh |
| Schedule 25P | 0.093¢ per kwh |
| Schedules 31 & 32 | 0.151¢ per kwh |

Flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service are to be increased by the following percentage:

| | |
|---|---|
| Schedules 41-49 | 2.448% |

SPECIAL TERMS AND CONDITIONS:

The rates set forth under this Schedule are subject to periodic review and adjustment by the IPUC based on the actual balance of deferred power costs.

Service under this schedule is subject to the Rules and Regulations contained in this tariff.

The above Rate is subject to increases as set forth in Tax Adjustment Schedule 58.

AVISTA CORPORATION
d/b/a Avista Utilities

# SCHEDULE 91

## ENERGY EFFICIENCY RIDER ADJUSTMENT - IDAHO

APPLICABLE:

To Customers in the State of Idaho where the Company has electric service available. This Energy Efficiency Rider or Rate Adjustment shall be applicable to all retail customers for charges for electric energy sold and to the flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service. This Rate Adjustment is designed to recover costs incurred by the Company associated with providing energy efficiency services and programs to customers.

MONTHLY RATE:

The energy charges of the individual rate schedules are to be increased by the following amounts:

| | | | |
|---|---|---|---|
| Schedule 1 | - .081¢ per kWh | Schedule 25 | - .052¢ per kWh |
| Schedule 11 & 12 | - .095¢ per kWh | Schedule 25P | - .046¢ per kWh |
| Schedule 21 & 22 | - .073¢ per kWh | Schedule 31 & 32 | - .076¢ per kWh |

Flat rate charges for Company-owned or Customer-owned Street Lighting and Area Lighting Service are to be increased by 1.25%.

SPECIAL TERMS AND CONDITIONS:

Service under this schedule is subject to the Rules and Regulations contained in this tariff.

The above Rate is subject to increases as set forth in Tax Adjustment Schedule 58.

**Duke Energy Indiana, Inc.**
**1000 East Main Street**
**Plainfield, Indiana 46168**



## RATE HLF—SCHEDULE FOR HIGH LOAD FACTOR SERVICE

### Availability

Available to any customer contracting for a specified capacity of not less than 25 kW. Applicant must be located adjacent to an electric transmission or distribution line of Company that is adequate and suitable for supplying the service requested.

### Character of Service

Alternating current having a frequency of sixty Hertz and furnished in accordance with the provisions set forth hereunder.

### Rate*

**Connection Charges per Month:**

| | |
|---|---|
| Secondary | $ 15.00 |
| Primary and Primary Direct | $ 75.00 |
| Transmission | $300.00 |

Maximum Load Charge (Monthly)

| | |
|---|---|
| Transmission Line Service at nominal voltage of 138,000, 230,000 or 345,000 Volts<br>Each kW of Billing Maximum Load | $ 10.35 per kW |
| Transmission Line Service at nominal voltage of 69,000 Volts<br>Each kW of Billing Maximum Load | $ 10.83 per kW |
| Primary Direct Service at nominal voltage of 2,400 to 34,500 Volts<br>Each kW of Billing Maximum Load | $ 12.05 per kW |
| Primary Service at nominal voltage of 2,400 to 34,500 Volts<br>Each kW of Billing Maximum Load | $ 13.08 per kW |
| Secondary Service at nominal voltage of 480 Volts or lower<br>Each kW of Billing Maximum Load | $ 14.06 per kW |

**Energy Charge** (In addition to the Maximum Load Charge)

| | |
|---|---|
| Transmission Line Service at nominal voltage of 138,000, 230,000 or 345,000 Volts<br>For All Energy Used Per Month | $0.015848 per kWh |
| Transmission Line Service at nominal voltage of 69,000 Volts<br>For All Energy Used Per Month | $0.015904 per kWh |
| Primary Direct Service at nominal voltage of 2,400 to 34,500 Volts<br>For All Energy Used Per Month | $0.016065 per kWh |
| Primary Service at nominal voltage of 2,400 to 34,500 Volts<br>For All Energy Used Per Month | $0.016275 per kWh |
| Secondary Service at nominal voltage of 480 Volts or lower<br>For All Energy Used Per Month | $0.016830 per kWh |

**KVAr Charge**

| | | |
|---|---|---|
| For Each kVAr of the Monthly Billed kVAr Demand | $0.24 | per kVAr |

## RATE HLF—SCHEDULE FOR HIGH LOAD FACTOR SERVICE

### Monthly Minimum Charge

The monthly minimum charge shall be the Maximum Load Charge.

### Measurements of Maximum Load and Energy

Maximum Load shall be measured by suitable recording instruments provided by Company. The Metered Maximum Load shall be the customer's highest average thirty-minute kW load in the billing period.

When energy is measured through more than one meter (permitted in the case of metering at a voltage of 480 Volts or lower under Paragraph 4 of Special Terms and Conditions) the Maximum Loads, separately determined for each meter, shall be added together for determining the Maximum Load for the month.

Energy shall be measured by suitable integrating instruments provided by Company.

### Metering Adjustments

At the option of the Company, service hereunder may be metered at voltage levels different from delivered voltages. In the event metered voltages exceed delivered voltages, before computing the charges, the actual measurement of energy, kVAr and Billing Maximum Load shall be decreased by one percent (1%). In the event delivered voltages exceed metered voltages, before computing the charges, the actual measurement of energy, kVAr and Billing Maximum Load shall be increased by one percent (1%).

### Billing Maximum Load

The Billing Maximum Load will equal the Metered Maximum Load in kW adjusted for metering adjustments, if applicable. In no event shall the Billing Maximum Load be less than 25 kW.
Billing of kVAr

For Customers who have pulse metering, the billed kVAr demand will be determined by trigonometric calculation using the customer's peak 30 minute kW demand for the month and the power factor coincident with the peak 30 minute kW demand for the month. For Customers who do not have pulse metering, the billed kVAr demand will be determined by trigonometric calculation using the Customer's peak 30 minute kW demand for the month and the average power factor for the month.

### Special Terms and Conditions

1. For Customers taking transmission or primary service, Customer shall furnish, own, and maintain, at his own expense, the complete substation structure and equipment, including switches and protective equipment, transformers and other apparatus, any or all of which is necessary for Customer to take service at the standard primary or transmission line voltage selected by Company. Company will, however, furnish, own, operate, and maintain all necessary metering equipment. Failure of a customer to provide proper maintenance on facilities described hereinabove which results in premature equipment failure and/or interruption to the Company's other customers shall be considered negligent and the Company may require the Customer to install protective equipment as specified by the Company in order to provide the necessary protection and isolation. Said protective equipment shall be furnished, owned, and maintained by the Customer, however, in certain instances Company retains the option of requiring the Customer to enter into a specific maintenance agreement with the Company. Company also retains the option of furnishing, owning, and maintaining said protective equipment as per "Standard Contract Rider No. 53—Excess Facilities."

## RATE HLF—SCHEDULE FOR HIGH LOAD FACTOR SERVICE

**Special Terms and Conditions (Contd.)**

2. All wiring, pole lines, wires, and other electrical equipment and apparatus located beyond point of connection of Customer's service lines with the lines of Company are considered the distribution system of Customer and shall be furnished, owned, and maintained by Customer, except in the case of metering equipment and other equipment incidental to the rendering of service, if any, that is furnished, owned and maintained by Company, and installed beyond point of connection.

3. The Company normally does not provide transformations within the transmission and/or primary service classifications as described in the transmission and primary maximum load charges. However, in the case of unusual service requests where the Company's existing facilities adjacent to the Customer are inadequate, the Company may furnish such transformations upon Customer paying the appropriate excess facilities charge. The Company shall not furnish, own, and maintain such transformers on an excess facilities basis solely for the purpose of modifying Paragraph 1 on the previous page.

4. The rates hereunder are predicated upon the supply of service being delivered at a single location in such a manner that the measurement of the various components of the service may be made through one metering installation, except that service metered at a voltage of 480 Volts or lower may be furnished through not more than one meter for the lighting service and one meter for the power service, unless it is required by law to install a separate service for exit lighting, in which case an additional meter will be installed for the exit lighting.

5. During certain scheduled periods of time, Customers served at primary voltage and higher may perform normal maintenance or repair that will result in a partial or total reduction in electrical consumption during certain monthly billing periods. Such maintenance or repair period may be scheduled and agreed upon by Customer and Company at least thirty (30) days prior to such period. There shall be a maximum of two (2) such scheduled periods in a twelve-month consecutive period not to exceed 14 days in total duration for both such periods.

   Whenever such maintenance or repair periods have been scheduled with and agreed to by Company, Customer will be billed for the actual maximum load during such periods on the basis of the proration of the Maximum Load Charge. Such proration will be based on the ratio of the number of days in the scheduled maintenance or repair period, divided by thirty (30) days. The actual energy used during the maintenance or repair period will be billed according to the Energy Charge of this rate schedule.

   For all of the other days during the monthly billing period in which there has been a scheduled maintenance or repair period, Customer will be billed for the maximum load, as determined by the Billing Maximum Load provision of this rate schedule, multiplied by the complement of the above computed prorate ratio. The Energy Charge will be computed on the actual energy used during the remaining portion of the monthly billing period.

   A $500.00 fee will be imposed on customers taking advantage of the Maintenance Period Provision, but only at those times when such periods are taken.

   *Subject to:

   Standard Contract Rider No. 60—Fuel Cost Adjustment
   Standard Contract Rider No. 62—Qualified Pollution Control Property Revenue Adjustment
   Standard Contract Rider No. 63—$SO_2$ and $NO_x$ Emission Allowance Adjustment
   Standard Contract Rider No. 64—Merger Savings Credit
   Standard Contract Rider No. 66—Demand Side Management Adjustment
   Standard Contract Rider No. 67—Recovery of Preapproved Purchased Power Costs to Meet Retail Customer Peak Load Requirements (Purchased Power Tracker)
   Standard Contract Rider No. 68—Midwest ISO Management Cost and Revenue Adjustment
   Standard Contract Rider No. 70—Summer Reliability Adjustment
   Standard Contract Rider No. 71—Clean Coal Operating Cost Revenue Adjustment

| Month | Fuel Cost in Rates | Rider 60 Fuel Adjust. |
|---|---|---|
| Jan '06 | $ 0.014484 | $ 0.000232 ✓ |
| Apr '06 | 0.014484 | 0.000232 ✓ |
| Jul '06 | 0.014484 | 0.001052 ✓ |
| Oct '06 | 0.014484 | 0.007713 ✓ |
| Average | | 0.002307 ✓ |

# IURC 14 - DUKE ENERGY INDIANA, INC. -2006- Quarterly Rider

| JAN. - MAR. 2006 QUARTER 1 | RS | CS | LLF | HLF | TS |
|---|---|---|---|---|---|
| Fuel Rider 60 | $0.002322 | $0.002322 | $0.002322 | $0.002322 | $0.002322 |
| Qualified Pollution-Rider 62 | $0.000747 | $0.000761 | $0.000726 | $0.000602 | $0.000539 |
| Emission Allow. Rider 63 | $0.001140 | $0.001140 | $0.001140 | $0.001140 | $0.001140 |
| Emission Allow. Rider 63[1] | $0.001794 | $0.001794 | $0.001794 | $0.001794 | $0.001794 |
| DSM On-Going Expenses, Rider 66 | $0.000356 | ($0.000031) | ($0.000031) | ($0.000031) | $0.000000 |
| Purchased Power Tracker Rider No. 67 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| Midwest ISO Management Cost and Revenue Adjustment, Rider No. 68 | $0.000958 | $0.001153 | $0.001160 | $0.001003 | $0.000897 |
| Summer Reliability Adjustment, Rider No. 70 | $0.000262 | $0.000282 | $0.000215 | $0.000208 | $0.000159 |
| Clean Coal Operating Cost, Rider 71 | $0.000806 | $0.000775 | $0.000732 | $0.000607 | $0.000545 |

(1) Effective January 16, 2006

| APR. - JUNE. 2006 QUARTER 2 | RS | CS | LLF | HLF | TS |
|---|---|---|---|---|---|
| Fuel Rider 60 | $0.002322 | $0.002322 | $0.002322 | $0.002322 | $0.002322 |
| Fuel Rider 60[1] | $0.008179 | $0.008179 | $0.008179 | $0.008179 | $0.008179 |
| Qualified Pollution-Rider 62 | $0.000747 | $0.000761 | $0.000726 | $0.000602 | $0.000539 |
| Emission Allow. Rider 63 | $0.002898 | $0.002898 | $0.002898 | $0.002898 | $0.002898 |
| Merger Savings Credit, Rider 64[2] | ($0.002248) | ($0.001987) | ($0.001664) | ($0.001045) | ($0.001416) |
| DSM On-Going Expenses, Rider 66 | $0.000356 | ($0.000031) | ($0.000031) | ($0.000031) | $0.000000 |
| Purchased Power Tracker Rider No. 67 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| Midwest ISO Management Cost and Revenue Adjustment, Rider No. 68 | $0.003534 | $0.003302 | $0.003041 | $0.002410 | $0.002219 |
| Summer Reliability Adjustment, Rider No. 70 | $0.000262 | $0.000282 | $0.000215 | $0.000208 | $0.000159 |
| Clean Coal Operating Cost, Rider 71 | $0.000806 | $0.000775 | $0.000732 | $0.000607 | $0.000545 |

(1) Effective April 7, 2006
(2) Effective April 2006, Will be applied to Customers Billing starting with June 2006 bills.

| JUL. - SEPT. 2006 QUARTER 3 | RS | CS | LLF | HLF | TS |
|---|---|---|---|---|---|
| Fuel Rider 60 | $0.010520 | $0.010520 | $0.010520 | $0.010520 | $0.010520 |
| Qualified Pollution-Rider 62 | $0.001480 | $0.001560 | $0.001516 | 0.652214[1] | $0.001173 |
| Emission Allow. Rider 63 | $0.002158 | $0.002158 | $0.002158 | $0.002158 | $0.002158 |
| Merger Savings Credit, Rider 64 | ($0.002248) | ($0.001987) | ($0.001664) | ($0.001045) | ($0.001416) |
| DSM On-Going Expenses, Rider 66 | $0.000356 | ($0.000031) | ($0.000031) | ($0.000031) | $0.000000 |
| Purchased Power Tracker Rider No. 67 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| Midwest ISO Management Cost and Revenue Adjustment, Rider No. 68 | $0.001166 | $0.001247 | $0.001571 | $0.001384 | $0.001172 |
| Summer Reliability Adjustment, Rider No. 70 | $0.000647 | $0.000691 | $0.000601 | $0.000512 | ($0.000583) |
| Summer Reliability Adjustment, Rider No. 70[2] | $0.000385 | $0.000409 | $0.000386 | $0.000304 | ($0.000742) |
| Clean Coal Operating Cost, Rider 71 | $0.000695 | $0.000749 | $0.000722 | 0.310358[1] | $0.000533 |

(1) The Rate HLF factor is billed on non-coincident demand.
(2) Efffective First Billing Cycle of September 2006

| OCT. - DEC. 2006 QUARTER 4 | RS | CS | LLF | HLF | TS |
|---|---|---|---|---|---|
| Fuel Rider 60 | $0.007713 | $0.007713 | $0.007713 | $0.007713 | $0.007713 |
| Qualified Pollution-Rider 62 | $0.001480 | $0.001560 | $0.001516 | 0.652214[1] | $0.001173 |
| Emission Allow. Rider 63 | ($0.000162) | ($0.000162) | ($0.000162) | ($0.000162) | ($0.000162) |
| Merger Savings Credit, Rider 64 | ($0.002248) | ($0.001987) | ($0.001664) | ($0.001045) | ($0.001416) |
| DSM On-Going Expenses, Rider 66 | $0.000618 | $0.000315 | $0.000315 | $0.000315 | $0.000000 |
| Purchased Power Tracker Rider No. 67 | $0.000000 | $0.000000 | $0.000000 | $0.000000 | $0.000000 |
| Midwest ISO Management Cost and Revenue Adjustment, Rider No. 68 | $0.002603 | $0.002733 | $0.002173 | $0.001511 | $0.001806 |
| Summer Reliability Adjustment, Rider No. 70 | $0.000385 | $0.000409 | $0.000386 | $0.000304 | ($0.000742) |
| Clean Coal Operating Cost, Rider 71 | $0.000695 | $0.000749 | $0.000722 | 0.310358[1] | $0.000533 |

(1) The Rate HLF factor is billed on non-coincident demand.

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 14
Tenth Revised Sheet No. 60
Cancels and Supersedes
Ninth Revised Sheet No. 60
Page 1 of 1

# STANDARD CONTRACT RIDER NO. 60
# FUEL COST ADJUSTMENT APPLICABLE TO ALL RETAIL RATE SCHEDULES

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per KWH to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S - $0.014484

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commisssion's Uniform System of Accounts for Class A and B Public Utilities and Licensees (FERC US of A);

   (b) the actual identifiable fossil and nuclear fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in ( c ) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generation from its own system, as computed in accordance with applicable Commission Orders,

2. "S" is the estimated kilowatt-hour sales as recorded on the Company's books and records in accordance with the FERC US of A for the same estimated period set forth in "F,"

B. The factor as computed above shall be modified to allow the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of fuel costs.

C. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

D. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of October 2006, the fuel cost adjustment shall be $0.007713 per kilowatt-hour.

E. From time to time, and subject to approval of the Commission, the factor shall be further modified to include the separate recovery, pursuant to Ind. Code 8-1-2-42(a), of costs applicable to certain power purchases in excess of the monthly purchased power benchmark.

**ISSUED: November 1, 2006**

**EFFECTIVE the later of the date of the Commission's Order or the first billing cycle of October 2006**

**Duke Energy Indiana, Inc.**
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**STANDARD CONTRACT RIDER NO. 62**
**QUALIFIED POLLUTION CONTROL**
**PROPERTY REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

The applicable charges for electric service to the Company's retail customers, to the extent so served, shall include a charge to reflect rate base treatment for qualified pollution control property in accordance with I.C. 8-1-2-6.6 and 170 IAC 4-6. The revenue adjustment applicable to the Company's charges for electric service will be determined under the following provision:

The Qualified Pollution Control Property Revenue Adjustment by Rate Group per billing cycle month shall be determined by multiplying the Qualified Pollution Control Property Revenue Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service.

Qualified Pollution Control Property
Revenue Adjustment Factor by Rate Group =

$$\frac{a \times b \times c \times d}{e}$$

where:

1. "a" is the jurisdictional cost of the Company's cumulative qualified pollution control property including costs of completed capital projects or parts of capital projects that comply with provisions of Commission Rule 170 IAC 4-6. For purposes of determining the value of such capital projects for this rate mechanism, the Company's costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act shall be used.

2. "b" is the Company's weighted average cost of capital as of the date of valuation of the qualified pollution control property.

3. "c" is the revenue conversion factor (after interest expense synchronization) used to convert return to operating revenues.

4. "d" is the individual retail rate group's production demand allocator used for allocation purposes in the cost of service study in Cause No. 42359.

5. "e" is the individual retail rate group's adjusted billing cycle kilowatt-hour sales for the twelve months ending as of the date of valuation of the qualified pollution control property.

6. The Qualified Pollution Control Property Revenue Adjustment Factor by Rate Group is as follows:

**DUKE ENERGY INDIANA, INC.**
**1000 East Main Street**
**Plainfield, Indiana 46168**



**STANDARD CONTRACT RIDER NO. 62**
**QUALIFIED POLLUTION CONTROL**
**PROPERTY REVENUE ADJUSTMENT FACTOR**
**APPLICABLE TO RETAIL RATE GROUPS**

| Line No. | Retail Rate Group | Qualified Pollution Control Property Revenue Adjustment Factor Per KWH (A) | Qualified Pollution Control Property Revenue Adjustment Factor Per Non-Coincident KW (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | $0.001480 | | 1 |
| 2 | Rates CS and FOC | 0.001560 | | 2 |
| 3 | Rate LLF | 0.001516 | | 3 |
| 4 | Rate HLF | | 0.652214 | 4 |
| 5 | Purdue-Supplemental | 0.000726 | | 5 |
| 6 | Impact/Net Forge | 0.001257 | | 6 |
| 7 | Nucor | 0.001026 | | 7 |
| 8 | Air Liquide | 0.000974 | | 8 |
| 9 | CSN | 0.000000 | | 9 |
| 10 | Rate OL | 0.000398 | | 10 |
| 11 | Rate WP | 0.001212 | | 11 |
| 12 | Rate SL | 0.000426 | | 12 |
| 13 | Rate AL | 0.000314 | | 13 |
| 14 | Rate MHLS | 0.000357 | | 14 |
| 15 | Rates MOLS and UOLS | 0.000074 | | 15 |
| 16 | Rates TS, FS and MS | $0.001173 | | 16 |

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**DUKE ENERGY INDIANA, INC.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 62**
**QUALIFIED POLLUTION CONTROL**
**PROPERTY REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

**ALLOCATED SHARE OF ADJUSTED SYSTEM PEAK DEMAND FOR**
**RETAIL CUSTOMERS BY RATE GROUP EXPRESSED**
**AS A PERCENTAGE OF THE COMPANY'S ADJUSTED TOTAL RETAIL SYSTEM PEAK**
**DEMAND AS DEVELOPED FOR COST OF SERVICE PURPOSES IN CAUSE NO. 42359**

| Line No. | Rate Groups | KW Share of System Peak (A) | Percent Share Of System Peak (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 1,582,005 | 36.727% | 1 |
| 2 | Rates CS and FOC | 224,244 | 5.206% | 2 |
| 3 | Rate LLF | 628,152 | 14.583% | 3 |
| 4 | Rate HLF | 1,808,566 | 41.987% | 4 |
| 5 | Purdue-Supplemental | 10,481 | 0.243% | 5 |
| 6 | Impact/Net Forge | 7,860 | 0.182% | 6 |
| 7 | Nucor | 19,045 | 0.442% | 7 |
| 8 | Air Liquide | 320 | 0.007% | 8 |
| 9 | CSN | 0 | 0.000% | 9 |
| 10 | Rate OL | 4,855 | 0.113% | 10 |
| 11 | Rate WP | 17,235 | 0.400% | 11 |
| 12 | Rate SL | 2,185 | 0.051% | 12 |
| 13 | Rate AL | 272 | 0.006% | 13 |
| 14 | Rate MHLS | 282 | 0.007% | 14 |
| 15 | Rates MOLS and UOLS | 69 | 0.002% | 15 |
| 16 | Rates TS, FS and MS | 1,893 | 0.044% | 16 |
| 17 | TOTAL RETAIL | 4,307,464 | 100.000% | 17 |

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**DUKE ENERGY INDIANA, INC.**
**1000 East Main Street**
**Plainfield, Indiana 46168**



**STANDARD CONTRACT RIDER NO. 62**
**QUALIFIED POLLUTION CONTROL**
**PROPERTY REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

**BILLING CYCLE KWH SALES FOR THE COMPANY'S**
**RETAIL CUSTOMERS BY RATE GROUP BASED**
**ON THE TWELVE-MONTH PERIOD ENDED DECEMBER 31, 2005**

| Line No. | Rate Groups | Billing Cycle KWH Sales (A) | Sum Of Monthly Non-Coincident Peak Demands (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 9,069,054,018 | | 1 |
| 2 | Rates CS and FOC | 1,220,140,097 | | 2 |
| 3 | Rate LLF | 3,516,566,507 | | 3 |
| 4 | Rate HLF | 12,258,779,958 | 23,533,348 | 4 |
| 5 | Purdue-Supplemental | 122,305,229 | | 5 |
| 6 | Impact/Net Forge | 52,920,802 | | 6 |
| 7 | Nucor | 157,412,966 | | 7 |
| 8 | Air Liquide | 2,627,834 | | 8 |
| 9 | CSN | 0 | | 9 |
| 10 | Rate OL | 103,669,484 | | 10 |
| 11 | Rate WP | 120,613,158 | | 11 |
| 12 | Rate SL | 43,743,651 | | 12 |
| 13 | Rate AL | 6,991,164 | | 13 |
| 14 | Rate MHLS | 7,175,451 | | 14 |
| 15 | Rates MOLS and UOLS | 9,859,837 | | 15 |
| 16 | Rates TS, FS and MS | 13,711,134 | | 16 |
| 17 | TOTAL RETAIL | 26,705,571,290 | | 17 |

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**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168

IURC NO. 14
Eleventh Revised Sheet No. 63
Cancels and Supersedes
Tenth Revised Sheet No. 63
Page 1 of 1

## STANDARD CONTRACT RIDER NO. 63
## $SO_2$ AND $NO_x$ EMISSION ALLOWANCE ADJUSTMENT
## APPLICABLE TO ALL RETAIL RATE SCHEDULES

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($.000001) per kWh to recover and/or credit the cost for $SO_2$ and $NO_x$ emission allowances in accordance with the following formula:

$$SO_2 \text{ and } NO_x \text{ Emission Allowance Adjustment Factor} = \frac{a + b \pm c}{s}$$

where:

1. " $SO_2$" and "$NO_x$- emission allowances costs shall be defined as the estimated expense of $SO_2$ and $NO_x$ emission allowances applicable to native load customers based on estimated average costs over the three month period beginning with the first month of the billing cycle net of realized gains and losses as detailed in "c" below and consisting of the following components:

   (a) the average cost of $SO_2$ and $NO_x$ emission allowances consumed due to the operation of the Company's own generating units used to serve native load customers based on charges recorded on the Company's books and records in accordance with the Federal Energy Regulatory Commission's Uniform System of Accounts for Class A and B Public Utilities and Licenses plus;

   (b) The cost of $SO_2$ and $NO_x$ emission allowances incurred to serve native load customers associated with energy purchased or transferred for economy, reliability and operating purposes to the extent such costs are specifically identified or can be reasonably estimated less;

   (c) net gains and losses (net of transaction costs) realized during the preceding quarter from sales of $SO_2$ and $NO_x$ emission allowances allocated to or purchased by PSI for native load customer requirements.

2. "S" is the estimated native load kilowatt-hour sales for the same period that $SO_2$ and $NO_x$ emission allowance costs have been estimated.

B. The factor as computed above shall be modified to allow for the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of $SO_2$ and $NO_x$ emission allowance costs.

C. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between estimated $SO_2$ and $NO_x$ emission allowance costs billed and $SO_2$ and $NO_x$ emission allowance costs actually incurred during the first and succeeding billing cycle month(s) in which such estimated $SO_2$ and $NO_x$ emission allowance costs were billed.

D. Effective for all bills rendered beginning with and subsequent to the July 2006 billing cycle, the $SO_2$ and $NO_x$ emission allowance adjustment shall be $0.002158 per kilowatt-hour.

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1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 64**
**MERGER SAVINGS CREDIT RIDER**
**APPLICABLE TO RETAIL RATE GROUPS**

## Availability

The applicable energy charges for service to the Company's retail electric customers shall be decreased monthly to reflect the sharing of the Cinergy Corp. / Duke Energy Corporation merger savings, net of merger costs, per the merger savings sharing plan approved by the Commission in Cause No. 42873. The application of the merger savings credit rider shall begin 30-60 days after consummation of the merger, and shall remain in effect for twelve (12) months. Thereafter, it shall expire by its own terms with no further action required by the Company or the IURC.

## Rate

The following are the monthly merger savings credit rider rates:

| Line No. | Retail Rate Group | Rate Per kWh | Line No. |
|---|---|---|---|
| 1 | Rate RS | ($0.002248) | 1 |
| 2 | Rates CS and FOC | ($0.001987) | 2 |
| 3 | Rate LLF | ($0.001664) | 3 |
| 4 | Rate HLF | ($0.001045) | 4 |
| 5 | Purdue - Supplemental | ($0.000782) | 5 |
| 6 | Impact/Net Forge | ($0.001266) | 6 |
| 7 | Nucor | ($0.001997) | 7 |
| 8 | Air Liquide | ($0.001903) | 8 |
| 9 | CSN | ($0.000122) | 9 |
| 10 | Rate OL | ($0.002697) | 10 |
| 11 | Rate WP | ($0.001251) | 11 |
| 12 | Rate SL | ($0.005131) | 12 |
| 13 | Rate AL | ($0.006854) | 13 |
| 14 | Rate MHLS | ($0.001217) | 14 |
| 15 | Rates MOLS and UOLS | ($0.003812) | 15 |
| 16 | Rates FS, TS and MS | ($0.001416) | 16 |

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



## STANDARD CONTRACT RIDER NO. 66
## DEMAND SIDE MANAGEMENT ADJUSTMENT
## APPLICABLE TO RETAIL RATE GROUPS

A. The applicable charges for electric service to the Company's retail electric customers shall include a charge to recover on-going Demand Side Management (DSM) expenses. The adjustment to the applicable charges for electric service will be determined under the following provision:

The monthly DSM billing adjustment shall be determined by multiplying the DSM adjustment factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour calculated in accordance with the following formula, by them monthly billed kilowatt-hours in the case of customers receiving method metered service and by the estimated monthly billed kilowatt-hours used for rate determinations in the case of customers receiving Unmetered service. The DSM billing adjustment will not be billed to commercial and/or industrial customers with an annual billed peak demand greater than 500 kilowatts based on customer usage for the latest twelve months available.

DSM Adjustment Factor =

$$\frac{a}{b}$$

where:

1. "a" is the sum of annual DSM program costs by individual retail rate group.
2. "b" is the applicable annual billing cycle kilowatt-hour sales by individual retail rate group which shall exclude kilowatt-hour sales to commercial and industrial customers with an annual peak billing demand greater than 500 kW, based on amounts billed during the latest twelve months available.
3. The factor as computed above shall be further modified to allow for the recovery of utility receipts taxes and/or other similar revenue based tax charges resulting from the recovery of annual DSM program costs.
4. The DSM Adjustment Factor by Rate Group is as follows:

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 66**
**DEMAND SIDE MANAGEMENT ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

| Line No. | Retail Rate Group | Demand Side Management Revenue Adjustment Factor Per kWh (Note) | Line No. |
|---|---|---|---|
| 1 | Rate RS | $ 0.000618 | 1 |
| 2 | Rates CS and FOC | $ 0.000315 | 2 |
| 3 | Rate LLF | $ 0.000315 | 3 |
| 4 | Rate HLF | $ 0.000315 | 4 |
| 5 | Purdue-Supplemental | $ 0.000000 | 5 |
| 6 | Impact/Net Forge | $ 0.000000 | 6 |
| 7 | Nucor | $ 0.000000 | 7 |
| 8 | Air Liquide | $ 0.000000 | 8 |
| 9 | CSN | $ 0.000000 | 9 |
| 10 | Rate OL | $ 0.000000 | 10 |
| 11 | Rate WP | $ 0.000000 | 11 |
| 12 | Rate SL | $ 0.000000 | 12 |
| 13 | Rate AL | $ 0.000000 | 13 |
| 14 | Rate MHLS | $ 0.000000 | |
| 15 | Rates MOLS and UOLS | $ 0.000000 | 15 |
| 16 | Rates TS, FS AND MS | $ 0.000000 | 16 |

Note: The above factors do not apply to commercial and industrial customers with a peak demand greater than 500 kW during the prior calendar year.

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 66**
**DEMAND SIDE MANAGEMENT ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

ASSIGNMENT OF DEMAND SIDE MANAGEMENT (DSM)
ON-GOING COST RECOVERY BY RETAIL RATE GROUP BASED ON THE
PROVISIONS OF THE COMMISSION'S ORDERS IN CAUSE NOS. 41875, 42325 AND 42612

| Line No. | Retail Rate Group (Note) | Calendar Year 2006 On-Going Expense (Note) | Line No. |
|---|---|---|---|
| 1 | Rate RS | $5,125,000 | 1 |
| 2 | Rates CS, FOC, LLF and HLF | 525,000 | 2 |
| 3 | Purdue-Supplemental | 0 | 3 |
| 4 | Impact/Net Forge | 0 | 4 |
| 5 | Nucor | 0 | 5 |
| 6 | Air Liquide | 0 | 6 |
| 7 | CSN | 0 | 7 |
| 8 | Rate OL | 0 | 8 |
| 9 | Rate WP | 0 | 9 |
| 10 | Rate SL | 0 | 10 |
| 11 | Rate AL | 0 | 11 |
| 12 | Rate MHLS | 0 | 12 |
| 13 | Rates MOLS and UOLS | 0 | 13 |
| 14 | Rates TS, FS and MS | 0 | 14 |
| 15 | Total Retail | $5,650,000 | 15 |

Note: The on-going expense amount shall not be applicable to commercial and industrial customers with an annual peak demand greater than 500 kW for the prior calendar year.

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1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 66**
**DEMAND SIDE MANAGEMENT ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

BILLING CYCLE KWH SALES FOR THE COMPANY'S
RETAIL CUSTOMERS BY RATE GROUP
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2004

| Line No. | Retail Rate Group (Note) | Adjusted Billing Cycle KWH Sales (Note) | Line No. |
|---|---|---|---|
| 1 | Rate RS | 8,373,784,599 | 1 |
| 2 | Rates CS and FOC | 1,176,966,719 | 2 |
| 3 | Rate LLF | 2,327,108,520 | 3 |
| 4 | Rate HLF | 1,208,956,442 | 4 |
| 5 | Purdue-Supplemental | 0 | 5 |
| 6 | Impact/Net Forge | 0 | 6 |
| 7 | Nucor | 0 | 7 |
| 8 | Air Liquide | 0 | 8 |
| 9 | CSN | 0 | 9 |
| 10 | Rate OL | 0 | 10 |
| 11 | Rate WP | 0 | 11 |
| 12 | Rate SL | 0 | 12 |
| 13 | Rate AL | 0 | 13 |
| 14 | Rate MHLS | 0 | 14 |
| 15 | Rates MOLS and UOLS | 0 | 15 |
| 16 | Rates TS, FS and MS | 0 | 16 |
| 17 | Total Retail | 13,086,816,280 | 17 |

Note: The adjusted billing cycle kWh Sales shall exclude all commercial and industrial customers with an annual peak demand peak demand greater than 500 kW for the prior calendar year.

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**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



# Standard Contract Rider No. 67
# Recovery of Preapproved Purchased Power Costs to Meet Retail Customer Peak Load Requirements (Purchased Power Tracker)

On April 17, 2004, the Commission approved the recovery of certain jurisdictional purchased power charges (1) that were shown to be reasonable and necessary to serve the peak load requirements of native load customers subject to the jurisdiction of the IURC and (2) that would not otherwise be recovered through the fuel adjustment charge.

The applicable charges for electric service to the Company's retail electric customers shall be increased, to the nearest 0.001 mill ($0.000001) per kWh, beginning with and subsequent to the effective date of the order in Cause No. 42359 to recover the estimated cost of purchased power required to serve jurisdictional retail customers loads, in accordance with the following formula:

Purchased Power Factor:

$$\frac{[(a-b-c)(90\%)](d)}{e}$$

where:

1. "a" equals the total cost of purchased power to meet customers' summer peak load as approved by the Indiana Utility Regulatory Commission. The total cost of purchased power shall include all charges relating to such purchases including, but not limited to, demand, capacity, reservation, and, or, option payments, energy, fuel, or other equivalent charges, including profits thereon.

2. "b" is the total estimated energy component of the preapproved purchased power costs to meet customers' summer peak load requirements as approved for recovery by the Indiana Utility Regulatory Commission through the fuel adjustment charge (Company's Standard Contract Rider No. 60).

3. "c" represents net profits from off-system sales, determined on and after the fact basis, resulting from the sale of power from generation "freed up" due to the tracked purchases.

4. "d" is the individual retail rate group's allocated share of the Company's system peak demand, based on the months of June, July, August and September as developed for cost of service purposes in Cause No. 42359 and as adjusted for the addition of "special contract" customers, expressed as a percentage of the Company's total system peak demands for such months.

5. "e" is the sum of individual retail rate groups' estimated kilowatt-hour sales for the approved period of recovery.

6. The factor as computed above shall be modified to allow for the recovery of the adjusted gross receipts tax or other similar revenue based taxes.

7. The subsequent Purchased Power Factor per Rate Group approved by the Indiana Utility Regulatory Commission shall be further modified to reflect the reconciliation of the difference between jurisdictional purchased power costs approved for recovery and the actual billing of such purchased power demand costs.

8. The Purchased Power Factor by Rate Group beginning with and subsequent to the effective date of the order in Cause No. 43259 is as follows:

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



# Standard Contract Rider No. 67
# Recovery of Preapproved Purchased Power Costs to Meet Retail Customer Peak Load Requirements (Purchased Power Tracker)

| Line No. | Rate Groups | Purchased Power Factor Per kWh to be Applied to Customer Bills Beginning With and Subsequent to the the Effective Date of the Order in Cause No. 42359 (A) | Line No. |
|---|---|---|---|
| 1 | Rate RS | $0.000000 | 1 |
| 2 | Rates CS and FOC | $0.000000 | 2 |
| 3 | Rate LLF | $0.000000 | 3 |
| 4 | Rate HLF | $0.000000 | 4 |
| 5 | Purdue-Supplemental | $0.000000 | 5 |
| 6 | Impact/Net Forge | $0.000000 | 6 |
| 7 | Nucor | $0.000000 | 7 |
| 8 | Air Liquide | $0.000000 | 8 |
| 9 | CSN | $0.000000 | 9 |
| 10 | Rate OL | $0.000000 | 10 |
| 11 | Rate WP | $0.000000 | 11 |
| 12 | Rate SL | $0.000000 | 12 |
| 13 | Rate AL | $0.000000 | 13 |
| 14 | Rate MHLS | $0.000000 | 14 |
| 15 | Rates MOLS and UOLS | $0.000000 | 15 |
| 16 | Rates TS. FS and MS | $0.000000 | 16 |

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



# Standard Contract Rider No. 67
# Recovery of Preapproved Purchased Power Costs to Meet Retail Customer Peak Load Requirements (Purchased Power Tracker)

ALLOCATED SHARE OF SYSTEM PEAK DEMAND FOR THE COMPANY'S RETAIL CUSTOMERS, BY RATE GROUP AND THE WHOLESALE ELECTRIC CUSTOMERS, EXPRESSED AS A PERCENTAGE OF THE COMPANY'S SYSTEM PEAK DEMAND DEVELOPED IN CAUSE NO. 42359
BASED ON THE FOUR MONTHS JUNE, JULY, AUGUST AND SEPTEMBER, 2002

| Line No. | Rate Groups | kW Share of Adjusted System Peak (A) | Percent Share Of Adjusted System Peak (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 1,912,350 | 34.396% | 1 |
| 2 | Rates CS and FOC | 287,915 | 5.179% | 2 |
| 3 | Rate LLF | 781,159 | 14.051% | 3 |
| 4 | Rate HLF | 2,002,337 | 36.017% | 4 |
| 5 | Purdue-Supplemental | 10,688 | 0.192% | 5 |
| 6 | Impact/Net Forge | 7,990 | 0.144% | 6 |
| 7 | Nucor | 19,097 | 0.344% | 7 |
| 8 | Air Liquide | 320 | 0.0076 | 8 |
| 9 | CSN | 0 | 0.000% | 9 |
| 10 | Rate OL | 0 | 0.000% | 10 |
| 11 | Rate WP | 17,497 | 0.315% | 11 |
| 12 | Rate SL | 0 | 0.000% | 12 |
| 13 | Rate AL | 0 | 0.000% | 13 |
| 14 | Rate MHLS | 0 | 0.000% | 14 |
| 15 | Rates MOLS and UOLS | 0 | 0.000% | 15 |
| 16 | Rates TS, FS and MS | 1,870 | 0.034% | 16 |
| 17 | TOTAL RETAIL | 5,041,223 | 90.678% | 17 |
| 18 | WHOLESALE | 518,236 | 9.322% | 18 |
| 19 | TOTAL COMPANY | 5,559,459 | 100.000% | 19 |

Issued: November 1. 2006

Effective: Beginning with and Subsequent to the November 1, 2006

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 68**
**MIDWEST INDEPENDENT SYSTEM OPERATOR ("MIDWEST ISO")**
**MANAGEMENT COST AND REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased for operation and maintenance expense treatment of Midwest ISO Management Cost and Revenues received from the Midwest ISO. The revenue adjustment to the applicable charges for electric service will be determined under the following provision:

The Midwest ISO Management Cost and Revenue Adjustment by Rate Group per any three consecutive billing cycle months shall be determined by multiplying the Midwest ISO Management Cost Adjustment Factor, as determined to the nearest 0.001 mill ($0.000001) per kilowatt-hour in accordance with the following formula, by the monthly billed kilowatt-hours for such three consecutive billing cycle months in the case of customers receiving metered service and by the estimated monthly kilowatt-hours used for rate determination in the case of customers receiving unmetered service. Midwest ISO Management Cost and Revenue Adjustment Factor Per Rate Group =

$$\frac{[((a + b + c + d - e) - (\$1{,}389{,}000 - \$2{,}726{,}000))\ h]\ f}{g}$$

where:

1. "a" is the Midwest ISO Management Costs billed PSI Energy, Inc., or a designee of PSI, under Service Schedule 10 – ISO Cost Recovery Adder of the Open Access Transmission and Energy Markets Tariff for the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO TEMT") or any successor Tariff.

2. "b" is the Midwest ISO Management Costs billed PSI Energy, Inc., or a designee of PSI, under Service Schedule 16 – Financial Transmission Rights Administrative Service Cost Recovery Adder of the Midwest ISO TEMT or any successor Tariff.

3. "c" is the Midwest ISO Management Costs billed PSI Energy, Inc., or a designee of PSI, under Service Schedule 17 – Energy Market Support Administrative Service Cost Recovery Adder of the Midwest ISO TEMT or any successor tariff.

4. "d" is the Midwest ISO Standard Market Design Costs billed PSI Energy, Inc., or a designee of PSI, or other Government mandated transmission costs PSI Energy, Inc., or a designee of PSI, is required to pay on behalf of retail customers.

5. "e" is the Midwest ISO transmission revenues assigned to the Company, collected by the Midwest ISO under the Midwest ISO TEMT or any successor Tariff.

6. $1,389,000 is the three (3) month average pro forma level of Midwest ISO Management Costs of which the jurisdictional electric allocated share is included by the Company in Cause No. 42359 in the determination of basic charges for service in its Electric Tariff.

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 68**
**MIDWEST INDEPENDENT SYSTEM OPERATOR ("MIDWEST ISO")**
**MANAGEMENT COST AND REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

7. $2,726,000 is the three (3) month average pro forma level of Midwest ISO transmission revenues, of which the jurisdictional electric allocated share is included by the Company in Cause No. 42359 in the determination of basic charges for services in its Electric Tariff.

8. "f" is the individual retail rate group's allocated share of the Company's retail peak demand developed for cost of service purposes in Cause No. 42359 expressed as a percentage of the Company's total retail peak demand.

9. "g" is the individual retail rate group's reported kilowatt-hour sales for the prior year during the same three (3) consecutive month period as the relevant three (3) billing cycle months.

10. "h" is the revenue conversion factor used to convert the applicable charges to operating revenues.

11. The Midwest ISO Management Cost Adjustment and Revenue Factor per Rate Group shall be further modified commencing with the three (3) consecutive months beginning with the sixth succeeding billing cycle month to reflect the difference between the incremental base monthly fees actually charged or credited to the retail electric customers and the incremental base monthly fees to be charged or credited to the retail electric customers during the three (3) consecutive billing cycle months, as determined above.

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



## STANDARD CONTRACT RIDER NO. 68
## MIDWEST INDEPENDENT SYSTEM OPERATOR ("MIDWEST ISO")
## MANAGEMENT COST AND REVENUE ADJUSTMENT
## APPLICABLE TO RETAIL RATE GROUPS

**ALLOCATED SHARE OF RETAIL PEAK DEMAND FOR THE COMPANY'S RETAIL CUSTOMERS BY RATE GROUP, EXPRESSED AS A PERCENTAGE OF THE COMPANY'S TOTAL RETAIL PEAK DEMAND DEVELOPED FOR COST OF SERVICE PURPOSES IN CAUSE NO. 42359**
**BASED ON THE TWELVE-MONTH PERIOD ENDED SEPTEMBER 30, 2002**

| Line No. | Rate Groups | KW Share of Retail Peak (A) | Percent Share of Retail Peak (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 1,582,005 | 36.728% | 1 |
| 2 | Rates CS | 224,244 | 5.206% | 2 |
| 3 | Rate LLF | 628,152 | 14.583% | 3 |
| 4 | Rate HLF | 1,808,566 | 41.986% | 4 |
| 5 | Purdue-Supplemental | 10,481 | 0.243% | 5 |
| 6 | Impact Forge | 7,860 | 0.183% | 6 |
| 7 | Nucor | 19,045 | 0.442% | 7 |
| 8 | Air Liquide | 320 | 0.007% | 8 |
| 9 | Rate OL | 4,855 | 0.113% | 9 |
| 10 | Rate WP | 17,235 | 0.400% | 10 |
| 11 | Rate SL | 2,185 | 0.051% | 11 |
| 12 | Rate AL | 272 | 0.006% | 12 |
| 13 | Rate MHLS | 282 | 0.006% | 13 |
| 14 | Rates MOLS and UOLS | 69 | 0.002% | 14 |
| 15 | Rates TS, FS, and MS | 1,893 | 0.044% | 15 |
| 16 | **TOTAL RETAIL** | 4,307,464 | 100.000% | 16 |

Issued: November 1, 2006

Effective: For the Billing Cycles of November and December 2006

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 68**
**MIDWEST INDEPENDENT SYSTEM OPERATOR ("MIDWEST ISO")**
**MANAGEMENT COST AND REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

The Midwest ISO Management Cost and Revenue Adjustment Factor by Rate Group applicable to the October, November and December 2006 billing cycles is as follows:

| Line No. | Retail Rate Group | Midwest ISO Management Cost and Revenue Adjustment Factor per KWH | Line No. |
|---|---|---|---|
| 1 | Rate RS | $ 0.002603 | 1 |
| 2 | Rates CS | $ 0.002733 | 2 |
| 3 | Rate LLF | $ 0.002173 | 3 |
| 4 | Rate HLF | $ 0.001511 | 4 |
| 5 | Purdue-Supplemental | $ 0.001023 | 5 |
| 6 | Impact Forge | $ 0.001996 | 6 |
| 7 | Nucor | $ 0.001565 | 7 |
| 8 | Air Liquide | $ 0.001493 | 8 |
| 9 | Rate OL | $ 0.000631 | 9 |
| 10 | Rate WP | $ 0.001899 | 10 |
| 11 | Rate SL | $ 0.000647 | 11 |
| 12 | Rate AL | $ 0.000504 | 12 |
| 13 | Rate MHLS | $ 0.000404 | 13 |
| 14 | Rates MOLS and UOLS | $ 0.000076 | 14 |
| 15 | Rates TS, FS, and MS | $ 0.001806 | 15 |

Issued: November 1, 2006

Effective: For the Billing Cycles of November and December 2006

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 70**
**SUMMER RELIABILITY ADJUSTMENT**
**APPLICABLE TO ALL RETAIL RATE SCHEDULES**

A. The applicable charges for electric service to the Company's retail electric customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the net jurisdictional cost of summer reliability purchases, PowerShare® program costs, and net profits from off-system sales, in accordance with the following formula:

Summer Reliability Adjustment Factor:

$$= \left[(a)(c)+(b)(d)+\left(\frac{(e)(f)-\$14{,}747{,}000}{2}\right)\right]*\left[\frac{1}{s}\right]$$

where:

1. "a" equals purchased power capacity costs (i.e., total cost of purchases, less fuel costs attributable to such purchases recoverable via Standard Contract Rider No. 60) associated with June through September reliability purchases as approved by the Commission. The total cost of summer reliability purchases shall include all charges relating to such purchases including, but not limited to, transmission, demand, capacity, reservation, and/or, option payments, or other equivalent charges, including profits thereon.

2. "b" is the total year-around amount of bill credit provided to customers under the Company's PowerShare® program, less the annual level built into base rates in Cause No. 42359 ($1,023,000). A two year pilot program will make PowerShare® credits available to applicable customers during all months. Likewise, applicable PowerShare® program cost-recovery would be extended from the months of June through September to all months.

3. "c" is the portion of the Company's summer coincident system peak demand allocated to customers by retail rate group, based on the months of June, July, August and September as developed for cost of service purposes in Cause No. 42359, expressed as a percentage of the Company's total system coincident peak demands for such months.

4. "d" is the portion of the Company's summer coincident system peak demand allocated to customers by retail rate group, based on the months of June, July, August and September as developed for cost of service purposes in Cause No. 42359, expressed as a percentage of the Company's total retail jurisdictional coincident peak demands for such months.

5. "e" represents actual net profits realized from off-system sales which shall not be less than zero. Actual off-system sales revenues shall be reduced by a fixed trading expense value of $3,953,000.

6. "f" is the individual retail rate group's allocated percentage share of Company's average twelve monthly coincident system peak demands as developed for cost of service purposes in Cause No. 42359.

7. "s" represents actual annual monthly kilowatt-hour sales by individual retail rate groups for the twelve months ending as of the conclusion of the summer peak season.

B. The factor as computed above shall be modified to allow for the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of net summer reliability costs.

C. The factor shall be further modified to reflect the reconciliation of annual net costs approved for recovery, by retail rate group, and actual annual amounts billed customers.

D. The summer reliability factor by rate group is as follows:

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 70**
**SUMMER RELIABILITY ADJUSTMENT**
**APPLICABLE TO ALL RETAIL RATE SCHEDULES**

| Line No. | Rate Groups | Estimated Summer Reliability Factor Per kWh to be Applied to Customer Bills (A) | Line No. |
|---|---|---|---|
| 1 | Rate RS | $0.000385 | 1 |
| 2 | Rates CS and FOC | $0.000409 | 2 |
| 3 | Rate LLF | $0.000386 | 3 |
| 4 | Rate HLF | $0.000304 | 4 |
| 5 | Purdue-Supplemental | $0.000255 | 5 |
| 6 | Impact/Net Forge | $0.000281 | 6 |
| 7 | NUCOR | $0.000237 | 7 |
| 8 | Air Liquide | $0.000221 | 8 |
| 9 | CSN | - | 9 |
| 10 | Rate OL | $0.000064 | 10 |
| 11 | Rate WP | $0.000304 | 11 |
| 12 | Rate SL | $0.000067 | 12 |
| 13 | Rate AL | $0.000049 | 13 |
| 14 | Rate MHLS | $0.000060 | 14 |
| 15 | Rates MOLS and UOLS | $0.000021 | 15 |
| 16 | Rates TS, FS and MS | ($0.000742) | 16 |

Issued: November 1, 2006

Effective: First Billing Cycle of
November, 2006

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 70**
**SUMMER RELIABILITY ADJUSTMENT**
**APPLICABLE TO ALL RETAIL RATE SCHEDULES**

ALLOCATED SHARE OF COINCIDENT SYSTEM PEAK DEMAND APPLICABLE TO COMPANY'S RETAIL CUSTOMERS, BY RATE GROUP, AND WHOLESALE ELECTRIC CUSTOMERS, EXPRESSED AS A PERCENTAGE OF THE COMPANY'S COINCIDENT SYSTEM PEAK DEMAND DEVELOPED IN CAUSE NO. 42359
BASED ON THE FOUR MONTHS JUNE, JULY, AUGUST AND SEPTEMBER, 2002

| Line No. | Rate Groups | kW Share of Summer System Peak (A) | Percent Share Of Summer System Peak (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 1,912,350 | 34.396% | 1 |
| 2 | Rates CS and FOC | 287,915 | 5.179% | 2 |
| 3 | Rate LLF | 781,159 | 14.051% | 3 |
| 4 | Rate HLF | 2,002,337 | 36.017% | 4 |
| 5 | Purdue-Supplemental | 10,688 | 0.192% | 5 |
| 6 | Impact/Net Forge | 7,990 | 0.144% | 6 |
| 7 | NUCOR | 19,097 | 0.344% | 7 |
| 8 | Air Liquide | 320 | 0.006% | 8 |
| 9 | CSN | - | - | 9 |
| 10 | Rate OL | - | - | 10 |
| 11 | Rate WP | 17,497 | 0.315% | 11 |
| 12 | Rate SL | - | - | 12 |
| 13 | Rate AL | - | - | 13 |
| 14 | Rate MHLS | - | - | 14 |
| 15 | Rates MOLS and UOLS | - | - | 15 |
| 16 | Rates TS, FS and MS | 1,870 | 0.034% | 16 |
| 17 | TOTAL RETAIL | 5,041,223 | 90.678% | 17 |
| 18 | WHOLESALE | 518,236 | 9.322% | 18 |
| 19 | TOTAL COMPANY | 5,559,459 | 100.000% | 19 |

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 70**
**SUMMER RELIABILITY ADJUSTMENT**
**APPLICABLE TO ALL RETAIL RATE SCHEDULES**

ALLOCATED SHARE OF THE AVERAGE MONTHLY COINCIDENT SYSTEM PEAK DEMANDS (12 CP) APPLICABLE TO COMPANY'S RETAIL CUSTOMERS, BY RATE GROUP, AND WHOLESALE ELECTRIC CUSTOMERS, EXPRESSED AS A PERCENTAGE OF THE COMPANY'S AVERAGE TWELVE MONTHLY COINCIDENT SYSTEM PEAK DEMANDS DEVELOPED IN CAUSE NO. 42359

| Line No. | Rate Groups | kW Share of System Peak (12 CP) (A) | Percent Share Of System Peak (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 1,582,005 | 33.713% | 1 |
| 2 | Rates CS and FOC | 224,244 | 4.779% | 2 |
| 3 | Rate LLF | 628,152 | 13.386% | 3 |
| 4 | Rate HLF | 1,808,566 | 38.540% | 4 |
| 5 | Purdue-Supplemental | 10,481 | 0.223% | 5 |
| 6 | Impact/Net Forge | 7,860 | 0.167% | 6 |
| 7 | NUCOR | 19,045 | 0.406% | 7 |
| 8 | Air Liquide | 320 | 0.007% | 8 |
| 9 | CSN | - | - | 9 |
| 10 | Rate OL | 4,855 | 0.103% | 10 |
| 11 | Rate WP | 17,235 | 0.367% | 11 |
| 12 | Rate SL | 2,185 | 0.047% | 12 |
| 13 | Rate AL | 272 | 0.006% | 13 |
| 14 | Rate MHLS | 282 | 0.006% | 14 |
| 15 | Rates MOLS and UOLS | 69 | 0.001% | 15 |
| 16 | Rates TS, FS and MS | 1,893 | 0.040% | 16 |
| 17 | TOTAL RETAIL | 4,307,464 | 91.791% | 17 |
| 18 | WHOLESALE | 385,190 | 8.209% | 18 |
| 19 | TOTAL COMPANY | 4,692,654 | 100.000% | 19 |

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 71**
**CLEAN COAL OPERATING COST**
**REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

The applicable charges for electric service to the Company's retail customers, shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh to reflect recovery of clean coal operating costs (depreciation and operation and maintenance expenses) in accordance with Ind. Code 8-1-8.8. The revenue adjustment applicable to the Company's charges for electric service, which shall be updated and reconciled to actual costs by the Company no more often than every six months, will be determined based on the following provisions:

$$\text{Clean Coal Cost Revenue Adjustment Factor by Rate Group} = \frac{[(a+b) \times c] \times d}{e}$$

Where:

1. "a" is the forecasted depreciation expense applicable to investments in clean coal energy projects that comply with provisions of Ind. Code 8-1-8.8. For purposes of determining the value of depreciation expense, the clean coal energy projects shall reflect the recovery of depreciation expense over a period of eighteen years beginning with the month following the in-service date of the applicable clean coal technology projects.

2. "b" is the forecasted operating expenses of the Company's clean coal energy projects (specifically, incremental operation and maintenance expense not reflected in base rates), associated with clean coal energy projects that comply with provisions of Ind. Code 8-1-8.8 and that have been approved by the Commission pursuant to Ind. Code 8-1-8.8. For purposes of determining the value of such operating expenses for this rate mechanism, the Company shall use costs as recorded in its books of account in accordance with the Uniform System of Accounts prescribed for Public Utilities and Licensees by the Federal Energy Regulatory Commission.

3. "c" is the revenue conversion factor used to convert the applicable operating expenses to operating revenues.

4. "d" is the individual rate group's jurisdictional production demand allocator used for allocation purposes in the cost of service study last approved by the IURC.

5. "e" is the individual retail rate group's adjusted billing cycle kilowatt-hour sales for the applicable six month period.

The factor shall be further modified to reflect the difference between estimated incremental operating costs billed and incremental operating costs actually experienced during the period such estimated operating costs were billed.

The clean coal operating cost revenue adjustment factor applicable to retail rate groups shall be as follows:

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 71**
**CLEAN COAL OPERATING COST**
**REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

| Line No. | Retail Rate Group | Clean Coal Operating Cost Revenue Adjustment Factor Per KWH (A) | Clean Coal Operating Cost Revenue Adjustment Factor Per Non-Coincident KW (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | $0.000695 | | 1 |
| 2 | Rates CS and FOC | 0.000749 | | 2 |
| 3 | Rate LLF | 0.000722 | | 3 |
| 4 | Rate HLF | | 0.310358 | 4 |
| 5 | Purdue-Supplemental | 0.000341 | | 5 |
| 6 | Impact/Net Forge | 0.000589 | | 6 |
| 7 | Nucor | 0.000472 | | 7 |
| 8 | Air Liquide | 0.000446 | | 8 |
| 9 | CSN | 0.000000 | | 9 |
| 10 | Rate OL | 0.000181 | | 10 |
| 11 | Rate WP | 0.000562 | | 11 |
| 12 | Rate SL | 0.000195 | | 12 |
| 13 | Rate AL | 0.000139 | | 13 |
| 14 | Rate MHLS | 0.000160 | | 14 |
| 15 | Rates MOLS and UOLS | 0.000037 | | 15 |
| 16 | Rates TS, FS and MS | $0.000533 | | 16 |

**Issued: November 1, 2006**

**Effective: November 1, 2006**

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 71**
**CLEAN COAL OPERATING COST**
**REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

**ALLOCATED SHARE OF SYSTEM PEAK DEMAND FOR**
**RETAIL CUSTOMERS BY RATE GROUP EXPRESSED**
**AS A PERCENTAGE OF THE COMPANY'S TOTAL RETAIL SYSTEM PEAK**
**DEMAND AS DEVELOPED FOR COST OF SERVICE PURPOSES IN CAUSE NO. 42359**

| Line No. | Rate Groups | KW Share of System Peak (A) | Percent Share Of System Peak (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 1,582,005 | 36.727% | 1 |
| 2 | Rates CS and FOC | 224,244 | 5.206% | 2 |
| 3 | Rate LLF | 628,152 | 14.583% | 3 |
| 4 | Rate HLF | 1,808,566 | 41.987% | 4 |
| 5 | Purdue-Supplemental | 10,481 | 0.243% | 5 |
| 6 | Impact/Net Forge | 7,860 | 0.182% | 6 |
| 7 | Nucor | 19,045 | 0.442% | 7 |
| 8 | Air Liquide | 320 | 0.007% | 8 |
| 9 | CSN | 0 | 0.000% | 9 |
| 10 | Rate OL | 4,855 | 0.113% | 10 |
| 11 | Rate WP | 17,235 | 0.400% | 11 |
| 12 | Rate SL | 2,185 | 0.051% | 12 |
| 13 | Rate AL | 272 | 0.006% | 13 |
| 14 | Rate MHLS | 282 | 0.007% | 14 |
| 15 | Rates MOLS and UOLS | 69 | 0.002% | 15 |
| 16 | Rates TS, FS and MS | 1,893 | 0.044% | 16 |
| 17 | TOTAL RETAIL | 4,307,464 | 100.000% | 17 |

**Issued: November 1, 2006**

**Effective: November 1, 2006**

**Duke Energy Indiana, Inc.**
1000 East Main Street
Plainfield, Indiana 46168



**STANDARD CONTRACT RIDER NO. 71**
**CLEAN COAL OPERATING COST**
**REVENUE ADJUSTMENT**
**APPLICABLE TO RETAIL RATE GROUPS**

**BILLING CYCLE KWH SALES FOR THE COMPANY'S**
**RETAIL CUSTOMERS BY RATE GROUP BASED**
**ON THE SIX-MONTH PERIOD ENDED JUNE 30, 2005**

| Line No. | Rate Groups | Billing Cycle KWH Sales (A) | Sum Of Monthly Non-Coincident Peak Demands (B) | Line No. |
|---|---|---|---|---|
| 1 | Rate RS | 4,416,766,738 | | 1 |
| 2 | Rates CS and FOC | 580,768,815 | | 2 |
| 3 | Rate LLF | 1,687,871,942 | | 3 |
| 4 | Rate HLF | 5,867,912,423 | 11,310,831 | 4 |
| 5 | Purdue-Supplemental | 59,603,243 | | 5 |
| 6 | Impact/Net Forge | 25,828,108 | | 6 |
| 7 | Nucor | 78,357,047 | | 7 |
| 8 | Air Liquide | 1,310,234 | | 8 |
| 9 | CSN | 0 | | 9 |
| 10 | Rate OL | 52,208,580 | | 10 |
| 11 | Rate WP | 59,462,885 | | 11 |
| 12 | Rate SL | 21,864,755 | | 12 |
| 13 | Rate AL | 3,602,293 | | 13 |
| 14 | Rate MHLS | 3,648,621 | | 14 |
| 15 | Rates MOLS and UOLS | 4,559,538 | | 15 |
| 16 | Rates TS, FS and MS | 6,896,390 | | 16 |
| 17 | TOTAL RETAIL | 12,870,661,612 | | 17 |

**Issued: November 1, 2006**

**Effective: November 1, 2006**

SCHEDULE OPT (NC)
OPTIONAL POWER SERVICE, TIME-OF-USE

AVAILABILITY (North Carolina Only)
Available to the individual customer.

Service under this Schedule shall be used solely by the contracting Customer in a single enterprise, located entirely on a single, contiguous premises.

This Schedule is not available to the individual customer who qualifies for a residential schedule, nor for auxiliary or breakdown service. Power delivered under this schedule shall not be used for resale or exchange or in parallel with other electric power or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Company, except at the option of the Company, or for service in conjunction with Rider SCG or Rider NM, under special terms and conditions expressed in writing in the contract with the customer.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power. The Company shall not be liable to any customer or applicant for power in the event it is delayed in or is prevented from, furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

TYPE OF SERVICE
The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts, 120/208 volts, 240/480 volts or other available single-phase voltages at the company's option; or
3-phase, 208Y/120 volts, 460Y/265 volts, 480Y/277 volts; or
3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts; or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than those listed above may be available at the Company's option if the size of the Customer's contract warrants a substation solely to serve that Customer, and if the Customer furnishes suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

The type of service supplied will depend upon the voltage available. Prospective customers should determine the available voltage by contacting the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators. The Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

RATE:

| | | | |
|---|---|---|---|
| I. | Basic Facilities Charge | $36.07 | |
| II. | Demand Charge | Summer Months | Winter Months |
| | A. On-Peak Demand Charge | June 1 – September 30 | October 1 – May 31 |
| | For the first 2000 kW of Billing Demand per month | $12.98 per kW | $7.64 per kW |
| | For the next 3000 kW of Billing Demand per month | $11.89 per kW | $6.54 per kW |
| | For all over 5000 kW of Billing Demand per month | $10.79 per kW | $5.43 per kW |
| | B. Economy Demand Charge | $1.03 per kW | $1.03 per kW |

III. Energy Charge
The Energy Charge for customers receiving service in establishments classified as "Manufacturing Industries" by the Standard Industrial Classification Manual published by the United States Government, and where more than 50% of the electric energy consumption of such establishment is used for its manufacturing processes is shown below under "Industrial Service". The rate for all other customers on this schedule is shown under "General Service".

| | General Service<br>All Months | Industrial Service<br>All Months |
|---|---|---|
| A. All On-Peak Energy per month | 4.8120 cents per kWh | 4.4296 cents per kWh |
| B. All Off-Peak Energy per month | 2.6766 cents per kWh | 2.2942 cents per kWh |

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

| | Summer Months<br>June 1 – September 30 | Winter Months<br>October 1 – May 31 |
|---|---|---|
| On-Peak Period Hours | 1:00 p.m. – 9:00 p.m.<br>Monday – Friday | 6:00 a.m. – 1:00 p.m.<br>Monday – Friday |
| Off-Peak Period Hours | All other weekday hours and all Saturday and Sunday hours. All hours for the following holidays shall be considered as Off-Peak: New Year's Day, Memorial Day, Good Friday, Independence Day, Labor Day, Thanksgiving Day, Day after Thanksgiving, and Christmas Day. | |

APPROVED FUEL CHARGE ADJUSTMENTS

The Company's approved fuel charge adjustments, if any, pursuant to North Carolina General Statute 62-133.2, will apply to all service supplied under this Schedule. The currently approved adjustments are included in the Rate above.

ADJUSTMENT FOR NET REVENUES FROM WHOLESALE SALES

The Company's Adjustment for Net Revenues from Wholesale Sales Rider will apply to service supplied to establishments classified as "Manufacturing Industries" by the Standard Industrial Classification Manual published by the United States Government, and where more than 50% of the electric energy consumption of such establishment is used for its manufacturing processes. The currently approved adjustment is included in the rate for Industrial Service shown above

DEFINITION OF "MONTH"

The term "month" as used in this Schedule means the period intervening between meter readings for the purposes of monthly billings. Readings are taken once a month at intervals of approximately thirty (30) days.

Summer months rates apply to service from June 1 through September 30. Winter months apply to service from October 1 through May 31.

CONTRACT DEMAND

The Company will require contracts to specify the maximum demand to be delivered to the Customer which shall be the Contract Demand.

Where the Customer can restrict on-peak demand to levels considerably below that of the Contract Demand, the Company may also contract for a limited On-Peak Contract Demand in addition to the Contract Demand.

DETERMINATION OF BILLING DEMAND

A. The On-Peak Billing Demand each month shall be the largest of the following:
   1. The maximum integrated thirty-minute demand during the applicable summer or winter on-peak period during the month for which the bill is rendered.
   2. Fifty percent (50%) of the Contract Demand (or 50% of the On-Peak Contract Demand if such is specified in the contract)
   3. 15 kilowatts (KW)

B. Economy Demand
   To determine the Economy Demand, the larger of
   1. The maximum integrated thirty-minute demand during the month for which the bill is rendered; or
   2. 50% of the Contract Demand

   shall be compared to the On-Peak Billing Demand as determined in A. above. If the demand determined by the larger of B. 1 and B. 2 above exceeds the On-Peak Billing Demand, the difference shall be the Economy Demand.

MINIMUM BILL

The minimum bill shall be the bill calculated on the Rate above including the Basic Facilities Charge, Demand Charge and Energy Charge, but the sum of the On-Peak Demand Charge and the Economy Demand Charge shall not be less than $1.64 per month per KW of Contract Demand. If the Customer's measured demand exceeds the Contract Demand, the Company may at any time establish the minimum based on the maximum integrated demand in the previous twelve months including the month for which the bill is rendered.

POWER FACTOR CORRECTION

When the average monthly power factor of the Customer's power requirements is less than 85 percent, the Company may correct the integrated demand in kilowatts for that month by multiplying by 85 percent and dividing by the average power factor in percent for that month.

PAYMENT

Bills under the Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one percent (1%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each customer shall enter into a contract to purchase electricity from the Company for a minimum original term of one (1) year, and thereafter from year to year upon the condition that either party can terminate the contract at the end of the original term, or at any time thereafter by giving at least sixty (60) days' previous notice of such termination in writing; but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

If the Customer requests an amendment to or termination of the service agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company an early termination charge as set forth in the Company's Service Regulations.

# RIDER IS (NC)
# INTERRUPTIBLE POWER SERVICE

Available at the Company's option to non-residential customers receiving concurrent service from the Company on Schedules G, GA, I, GT, IT, or OPT who are not served under Rider SCG.

Under this Rider the Customer agrees, at the Company's request, to reduce and maintain his load at a level specified in the individual contract. The Company's request to interrupt service may be at any time the Company has capacity problems. For non-residential customers who enter into a specific contract for interruptible power service, the following provisions apply in addition to the stated provisions of the Customer's rate schedule:

1. General Provisions:
   Contracts for interruptible power service will be accepted by the Company on the basis of successive contracts, and each contract shall specify an interruptible, integrated demand of not more than 50,000 KW to be subject to these provisions. The Company shall limit the acceptance of contracts to a total of 1,100,000 KW of Interruptible Contract Demand on all non-residential schedules on the total system.

   At the option of the Company, Customers may specify that the interruptible load provisions of this Rider be applicable only to a designated portion of the Customer's load which shall be submetered for the purposes of this Rider.

   Duke reserves the right to test the provisions of this Rider once per year if there has not been an occasion during the previous 12 months when the Company requested an interruption. Duke shall give advance notice of any test to customers served under this Rider.

   Continued service under this Rider is subject to satisfactory performance by the Customer, as determined by the Company, in response to the Company's request for interruption.

2. Definitions:

   Contract Demand: The Contract Demand is the maximum kilowatt demand which the Company shall be required to supply to the Customer.

   Interruptible Contract Demand: The Interruptible Contract Demand of not more than 50,000 KW is that portion of the Contract Demand which the Company will supply to the Customer at all times except during Interruption Periods.

   Firm Contract Demand: The Firm Contract Demand, which may be specified at different values for the summer months of June through September and the winter months of October through May, is that portion of the Contract Demand which the Company will supply to the Customer without limitation on the periods of availability.

   Interruption Period: An Interruption Period is that interval of time, initiated and terminated by the Company, during which the Customer will require service at no more than the Firm Contract Demand and the Company is obligated to supply no more than the Firm Contract Demand.

   Penalty Demand: The Penalty Demand is the maximum thirty (30) minute integrated demand required by the Customer during an Interruption Period in excess of the Firm Contract Demand.

   Exposure Period: The Exposure Period is that period of time within the month corresponding to the weekday peak demand periods and during which interruption under these provisions is most likely to occur. Specifically, the Exposure Period for the purpose of computing monthly credits is defined as follows:

   Summer Months of June through September
   1:00 p.m. to 9:00 p.m., Monday through Friday

   Winter Months of October through May
   6:00 a.m. to 1:00 p.m., Monday through Friday

   For customers served under Schedule OPT, the Exposure Period will exclude the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Day after Thanksgiving, and Christmas Day.

3. Control Notices and Limitations:
   The Customer shall be notified of all initiations of Interruption Periods at least thirty (30) minutes prior to such times, and the Customer shall fully comply with the Company's requests to reduce and maintain his load to not more than the Firm Contract Demand for the duration of the Interruption Period. The Customer shall be notified of all terminations of Interruption Periods.

   The Company may invoke interruption periods for not more than 150 hours in any year. Further, the Company shall have the right to invoke an interruption period at any time, subject to a maximum duration of 10 hours in any calendar day, which may be extended only by mutual agreement with the Customer.

4. Credit and Credit Computation:

Each month, a determination of the interruptible capacity available to the Company will be made in order to compute a credit. All energy consumed at a level above the Firm Contract Demand during the Exposure Period excluding the energy consumed above the Firm Contract Demand during interruption Periods, will be divided by the hours of duration of the Exposure Period excluding the hours of duration of Interruption Periods. The value thus computed will be reduced by the amount of the monthly maximum demand above the Firm Contract Demand which occurs during any Interruption Period. The resulting amount will be the Effective Interruptible Demand (EID) and shall not be less than zero.
The formula for computation is:

$$EID = \frac{KWH_{EP} - KWH_{IP}}{HOURS_{EP} - HOURS_{IP}} - KW_{MP}$$

Where: EID = Effective Interruptible Demand

$KWH_{EP}$ = Energy consumed during the Exposure Period above Firm Contract Demand

$KWH_{IP}$ = Energy consumed during Interruption Periods above Firm Contract Demand

$HOURS_{EP}$ = Hours of duration of the Exposure Period

$HOURS_{IP}$ = Hours of duration of the Interruption Periods

$KW_{MP}$ = Maximum monthly Penalty Demand

The amount of credit to be applied to the Customer's account each month will be determined by the formula:

Credit = EID x \$3.50 / $KW_{EID}$

5. Penalty and Penalty Computation:
Should the Customer fail to reduce and maintain his load at, or below the Firm Contract Demand during any Interruption Period, a penalty will be applied to the Customer's account for the month of occurrence. The penalty shall be computed by the formula:

Penalty = $\Sigma KW_P$ x \$10.00

Where: $\Sigma KW_P$ = the summation of the Penalty Demands occurring in each and every Interruption Period during the billing period.

6. A monthly "Extra Facilities Charge", equal to 1.7% of the installed cost of the extra facilities necessary for interruptible power service, but not less than \$25, shall be billed to the Customer in addition to the billing for energy or for demand plus energy, in accordance with the Extra Facilities provisions of the Company's Service Regulations.

7. Contract Period:

Contracts with interruptible load provisions shall be for a minimum original term of five (5) years and thereafter until terminated, by giving at least twelve (12) months' previous notice of such termination in writing, but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

The Company reserves the right to terminate the Customer's contract under this Rider at any time upon written notice to the Customer for failure of the Customer to reduce and maintain his load at or below the Firm Contract Demand during three or more Interruption Periods, or for violation of any of the terms or conditions of the applicable schedule or this Rider.

If the Customer requests an amendment to or termination of the service agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company an early termination charge as set forth in the Company's Service Regulations.

# FUEL COST ADJUSTMENT RIDER

AVAILABILITY (North Carolina Only)
Service supplied under the Company's rate schedules are subject to approved fuel charge adjustments, if any, over or under the Rate set forth in the approved rate schedules. Adjustments are made pursuant to North Carolina General Statute 62-133.2 as ordered by the North Carolina Utilities Commission.

APPROVED FUEL CHARGE ADJUSTMENTS
The Commission has ordered effective for service rendered on and after July 1, 2006 that such an adjustment shall be included in the Company's rate schedules and an appropriate fuel cost adjustment rider be filed together with the rate schedules to implement the changes to the fuel component.

Effective July 1, 2006 the Approved Fuel Cost was ordered increased from the 1.1032 ¢ / kWh Base Fuel Cost established November 12, 1991 in the general rate case Docket No. E-7, Sub 487 to 1.6770 ¢ / kWh.

APPROVED FUEL COST
The Approved Fuel Cost of 1.6770 ¢ / kWh will remain in effect until a new cost of fuel is established by the Commission.

EXPERIENCE MODIFICATION FACTOR
An Experience Modification Factor (EMF) decrement of 0.0069 ¢ / kWh and EMF interest decrement of 0.0010 ¢ / kWh is effective for service on and after July 1, 2006 and will continue until June 30, 2007

The following shows the calculation of the Approved Fuel Charge Adjustments:

| | Fuel Cost Effective July 1, 2005, E-7, Sub 780 | Fuel Cost Effective July 1, 2006, E-7, Sub 805 |
|---|---|---|
| Base Fuel Cost Effective November 12, 1991 Docket No. E-7, Sub 487 | 1.1032 ¢/kWh | 1.1032 ¢/kWh |
| Adjustment to Base Fuel Cost | .3429 ¢/kWh | .5738 ¢/kWh |
| Approved Fuel Cost | 1.4461 ¢/kWh | 1.6770 ¢/kWh |
| Experience Modification Factor | .0308 ¢/kWh | -.0069 ¢/kWh |
| Experience Modification Factor Interest | -------n/a------- | -.0010 ¢/kWh |
| Net Fuel Factor | 1.4769 ¢/kWh | 1.6691 ¢/kWh |
| Deferred Tax Decrement Rider | -.1975 ¢/kWh | ----- n/a------ |
| Net Factor | 1.2794 ¢/kWh | 1.6691 ¢/kWh |
| Change in Net Factor | | .3897 ¢/kWh |
| Gross Receipts Tax Multiplier | | X 1.033271 |
| Change in Rates | | .4027 ¢/kWh |

EFFECT ON RATES
As a result of the Commission June 27, 2006 Order in Docket No. E-7, Sub 805, the Approved Fuel Cost, Experience Modification Factor and Deferred Tax Decrement Rider are included in the current rate schedules effective for service on and after July 1, 2006. The effect of the Commission's Order, including its impact on the Company's gross receipts tax expense, is an increase in all rate schedules of 0.4027 ¢/kWh as compared to the rates in effect immediately prior to July 1, 2006.

USE OF RIDER
Since adjustments are already included in the Rates of the Company's current rate schedules which are effective for service on and after July 1, 2006, this Rider should not be used in addition to such rate schedules for bill calculations.

# SCHEDULE OPT (SC)
# OPTIONAL POWER SERVICE, TIME-OF-USE

AVAILABILITY (South Carolina Only)
Available to the individual customer.

Service under this Schedule shall be used solely by the contracting Customer in a single enterprise, located entirely on a single, contiguous premise.

This Schedule is not available to the individual customer who qualifies for a residential schedule, nor for auxiliary or breakdown service. Power delivered under this schedule shall not be used for resale or exchange or in parallel with other electric power or as a substitute for power contracted for or which may be contracted for, under any other schedule of the Company, except at the option of the Company, under special terms and conditions expressed in writing in the contract with the Customer.

The obligations of the Company in regard to supplying power are dependent upon its securing and retaining all necessary rights-of-way, privileges, franchises and permits, for the delivery of such power. The Company shall not be liable to any customer or applicant for power in the event it is delayed in, or is prevented from furnishing the power by its failure to secure and retain such rights-of-way, rights, privileges, franchises and permits.

TYPE OF SERVICE
The Company will furnish 60 Hertz service through one meter, at one delivery point, at one of the following approximate voltages, where available:

Single-phase, 120/240 volts, 120/208 volts, 240/480 volts or other available single-phase voltages at the company's option; or
3-phase, 208Y/120 volts, 460Y/265 volts, 480Y/277 volts; or
3-phase, 3-wire, 240, 460, 480, 575, or 2300 volts; or
3-phase, 4160Y/2400, 12470Y/7200, or 24940Y/14400 volts; or
3-phase voltages other than those listed above may be available at the Company's option if the size of the Customer's contract warrants a substation solely to serve that Customer, and if the Customer furnishes suitable outdoor space on the premises to accommodate a ground-type transformer installation, or substation, or a transformer vault built in accordance with the Company's specifications.

The type of service supplied will depend upon the voltage available. Prospective customers should determine the available voltage by contacting the nearest office of the Company before purchasing equipment.

Motors of less than 5 H.P. may be single-phase. All motors of more than 5 H.P. must be equipped with starting compensators. The Company reserves the right, when in its opinion the installation would not be detrimental to the service of the Company, to permit other types of motors.

RATE:

| | | | |
|---|---|---|---|
| I. | Basic Facilities Charge | $33.54 | |
| II. | Demand Charge | Summer Months | Winter Months |
| | A. On-Peak Demand Charge per month | June 1 – September 30 | October 1 – May 31 |
| | For the first 2000 kW of Billing Demand per month | $13.16 per kW | $7.69 per kW |
| | For the next 3000 kW of Billing Demand per month | $11.67 per kW | $6.40 per kW |
| | For all over 5000 kW of Billing Demand per month | $ 9.40 per kW | $4.74 per kW |
| | B. Economy Demand Charge per month | $1.01 per kW | $1.01 per kW |
| III. | Energy Charge | | |
| | A. All On-Peak Energy per month | 4.9854 cents per kWh | 4.9854 cents per kWh |
| | B. All Off-Peak Energy per month | 2.3253 cents per kWh | 2.3253 cents per kWh |

DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

| | Summer Months | Winter Months |
|---|---|---|
| | June 1 – September 30 | October 1 – May 31 |
| On-Peak Period Hours | 1:00 p.m. – 9:00 p.m. | 6:00 a.m. – 1:00 p.m. |
| | Monday – Friday | Monday – Friday |
| Off-Peak Period Hours | All other weekday hours and all Saturday and Sunday hours. | |

ADJUSTMENT FOR FUEL COSTS
The Company's Adjustment for Fuel Costs is incorporated as a part of, and will apply to all service supplied under, this Schedule.

DEFINITION OF "MONTH"

The term "month" as used in this Schedule means the period intervening between meter readings for the purposes of monthly billing. Readings are taken each month at intervals of approximately thirty (30) days.

Summer months' rates apply to service from June 1 through September 30. Winter months' rates apply to service from October 1 through May 31.

For customers in billing cycles 1-14 and 21-34, summer months' rates apply to the billing months of July through October. Winter months' rates apply to the billing months of November through June.

CONTRACT DEMAND

The Company will require contracts to specify the maximum demand to be delivered to the Customer which shall be the Contract Demand.

Where the Customer can restrict on-peak demand to levels considerably below that of the Contract Demand, the Company may also contract for a limited On-Peak Contract Demand in addition to the Contract Demand.

DETERMINATION OF BILLING DEMAND

A. The On-Peak Billing Demand each month shall be the largest of the following:

   1. The maximum integrated thirty-minute demand during the applicable summer or winter on-peak period during the month for which the bill is rendered.
   2. Fifty percent (50%) of the Contract Demand (or 50% of the On-Peak Contract Demand if such is specified in the contract)
   3. 15 kilowatts (kW)

B. Economy Demand
   To determine the Economy Demand, the larger of

   1. The maximum integrated thirty-minute demand during the month for which the bill is rendered; or
   2. 50% of the Contract Demand

   shall be compared to the On-Peak Billing Demand as determined in A. above. If the demand determined by the larger of B. 1 and B. 2 above exceeds the On-Peak Billing Demand, the difference shall be the Economy Demand.

MINIMUM BILL

The minimum bill shall be the bill calculated on the Rate above including the Basic Facilities Charge, Demand Charge and Energy Charge, but the sum of the On-Peak Demand Charge and the Economy Demand Charge shall not be less than $1.49 per month per kW of Contract Demand. If the Customer's measured demand exceeds the Contract Demand, the Company may at any time establish the minimum based on the maximum integrated demand in the previous twelve months including the month for which the bill is rendered.

POWER FACTOR CORRECTION

When the average monthly power factor of the Customer's power requirements is less than 85 percent, the Company may correct the integrated demand in kilowatts for that month by multiplying by 85 percent and dividing by the average power factor in percent for that month.

SALES TAX AND MUNICIPAL FEES

Any applicable sales tax, municipal service agreement fee, business license fee or other fee assessed by or remitted to a state or local governmental authority will be added to the charges determined above.

PAYMENT

Bills under the Schedule are due and payable on the date of the bill at the office of the Company. Bills are past due and delinquent on the fifteenth day after the date of the bill. If any bill is not so paid, the Company has the right to suspend service. In addition, all bills not paid by the twenty-fifth day after the date of the bill shall be subject to a one and one-half percent (1 1/2%) late payment charge on the unpaid amount. This late payment charge shall be rendered on the following month's bill and it shall become part of and be due and payable with the bill on which it is rendered.

CONTRACT PERIOD

Each customer shall enter into a contract to purchase electricity from the Company for a minimum original term of one (1) year, and thereafter from year to year upon the condition that either party can terminate the contract at the end of the original term, or at any time thereafter by giving at least sixty (60) days' previous notice of such termination in writing; but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

If the Customer requests an amendment to or termination of the agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company an early termination charge as set forth in the Company's Service Regulations.

# RIDER IS (SC)
# INTERRUPTIBLE POWER SERVICE

Available at the Company's option to non-residential customers receiving concurrent service from the Company on Schedules G, GA, I, GT, IT, OPT, or PG.

Under this Rider the Customer agrees, at the Company's request, to reduce and maintain his load at a level specified in the individual contract. The Company's request to interrupt service may be at any time the Company has capacity problems. For non-residential customers who enter into a specific contract for interruptible power service, the following provisions apply in addition to the stated provisions of the Customer's rate schedule:

1. General Provisions:
   Contracts for interruptible power service will be accepted by the Company on the basis of successive contracts, and each contract shall specify an interruptible, integrated demand of not more than 50,000 KW to be subject to these provisions. The Company shall limit the acceptance of contracts to a total of 1,100,000 KW of Interruptible Contract Demand on all non-residential schedules on the total system.

   At the option of the Company, Customers may specify that the interruptible load provisions of this Rider be applicable only to a designated portion of the Customer's load which shall be submetered for the purposes of this Rider.

   Duke reserves the right to test the provisions of this Rider once per year if there has not been an occasion during the previous 12 months when the Company requested an interruption. Duke shall give advance notice of any test to customers served under this Rider.

   Continued service under this Rider is subject to satisfactory performance by the Customer, as determined by the Company, in response to the Company's request for interruption.

2. Definitions:
   Contract Demand: The Contract Demand is the maximum kilowatt demand which the Company shall be required to supply to the Customer.
   Interruptible Contract Demand: The Interruptible Contract Demand of not more than 50,000 KW is that portion of the Contract Demand which the Company will supply to the Customer at all times except during Interruption Periods.
   Firm Contract Demand: The Firm Contract Demand, which may be specified at different values for the months of June through September and the months of October through May, is that portion of the Contract Demand which the Company will supply to the Customer without limitation on the periods of availability.
   Interruption Period: An Interruption Period is that interval of time, initiated and terminated by the Company, during which the Customer will require service at no more than the Firm Contract Demand and the Company is obligated to supply no more than the Firm Contract Demand.
   Penalty Demand: The Penalty Demand is the maximum thirty (30) minute integrated demand required by the Customer during an Interruption Period in excess of the Firm Contract Demand.
   Exposure Period: The Exposure Period is that period of time within the month corresponding to the weekday peak demand periods and during which interruption under these provisions is most likely to occur. Specifically, the Exposure Period for the purpose of computing monthly credits is defined as follows:

   Months of June through September
   1:00 p.m. to 9:00 p.m., Monday through Friday

   Months of October through May
   6:00 a.m. to 1:00 p.m., Monday through Friday

3. Control Notices and Limitations:
   The Customer shall be notified of all initiations of Interruption Periods at least thirty (30) minutes prior to such times, and the Customer shall fully comply with the Company's requests to reduce and maintain his load to not more than the Firm Contract Demand for the duration of the Interruption Period. The Customer shall be notified of all terminations of Interruption Periods.

   The Company may invoke interruption periods for not more than 150 hours in any year. Further, the Company shall have the right to invoke an interruption period at any time, subject to a maximum duration of 10 hours in any calendar day, which may be extended only by mutual agreement with the Customer.

4. Credit and Credit Computation:

Each month, a determination of the interruptible capacity available to the Company will be made in order to compute a credit. All energy consumed at a level above the Firm Contract Demand during the Exposure Period, excluding the energy consumed above the Firm Contract Demand during Interruption Periods, will be divided by the hours of duration of the Exposure Period excluding the hours of duration of Interruption Periods. The value thus computed will be reduced by the amount of the monthly maximum demand above the Firm Contract Demand which occurs during any Interruption Period. The resulting amount will be the Effective Interruptible Demand (EID) and shall not be less than zero.

The formula for computation is:

$$EID = \frac{KWH_{EP} - KWH_{IP}}{HOURS_{EP} - HOURS_{IP}} - KW_{MP}$$

Where: EID = Effective Interruptible Demand

$KWH_{EP}$ = Energy consumed during the Exposure Period above Firm Contract Demand

$KWH_{IP}$ = Energy consumed during Interruption Periods above Firm Contract Demand

$HOURS_{EP}$ = Hours of duration of the Exposure Period

$HOURS_{IP}$ = Hours of duration of the Interruption Periods

$KW_{MP}$ = Maximum monthly Penalty Demand

The amount of credit to be applied to the Customer's account each month will be determined by the formula:
Credit = EID x $3.50/$KW_{EID}$

5. Penalty and Penalty Computation:

Should the Customer fail to reduce and maintain his load at, or below, the Firm Contract Demand during any Interruption Period, a penalty will be applied to the Customer's account for the month of occurrence. The penalty shall be computed by the formula:

$$Penalty = \Sigma KW_P \times \$10.00$$

Where: $\Sigma KW_P$ = the summation of the Penalty Demands occurring in each and every Interruption Period during the billing period.

6. A monthly "Extra Facilities Charge," equal to 1.7% of the installed cost of the extra facilities necessary for interruptible power service, but not less than $25, shall be billed to the Customer in addition to the billing for energy, or for demand plus energy, in accordance with the Extra Facilities provisions of the Company's Service Regulations.

7. Contract Period:
Contracts with interruptible load provisions shall be for a minimum original term of five (5) years and thereafter until terminated, by giving at least twelve (12) months' previous notice of such termination in writing, but the Company may require a contract for a longer original term of years where the requirement is justified by the circumstances.

The Company reserves the right to terminate the Customer's contract under this Rider at any time upon written notice to the Customer for failure of the Customer to reduce and maintain his load at or below the Firm Contract Demand during three or more Interruption Periods, or for violation of any of the terms or conditions of the applicable schedule or this Rider.

If the Customer requests an amendment to or termination of the service agreement before the expiration of the initial term of the agreement, the Customer shall pay to the Company an early termination charge as set forth in the Company's Service Regulations

8. Sales Tax and Municipal Fees:
Any applicable sales tax, municipal service agreement fee, business license fee or other fee assessed by or remitted to a state or local governmental authority will be added to the charges determined above.

ADJUSTMENT FOR FUEL COSTS

APPLICABILITY

This adjustment is applicable to and is a part of the Utility's South Carolina retail electric rate schedules.

The Public Service Commission has determined that the costs of Fuel in an amount to the nearest one ten-thousandth of a cent, as determined by the following formula, will be included in the base rates to the extent determined reasonable and proper by the Commission.

$$F = E / S + G / S_1$$

Where:

F = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one ten-thousandth of a cent.

E = Total Projected system Fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees plus SO2 emission allowances recorded in Account 509. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

**Plus**

(B) Fuel costs related to purchased power (and applicable SO2 emission allowances) such as those incurred in unit power and limited term power purchases where the fossil fuel costs and applicable SO2 emission allowances associated with energy purchased are identifiable and are identified in the billing statement. Also the cost of 'firm generation capacity purchases' which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. "Costs of firm generation capacity purchases" include the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

**Plus**

(C) Fuel costs related to purchased power (including transmission charges and applicable SO2 emission allowances), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing utility's avoided variable costs for the generation of an equivalent quantity of electric power. Energy receipts that do not involve money payments such as Diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

**Minus**

(D) The cost of fuel and applicable $SO_2$ emission allowances recovered through intersystem sales including the fuel costs and applicable $SO_2$ emission allowances related to economy energy sales and other energy sold on an economic dispatch basis.
Energy deliveries that do not involve billing transactions such as Diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E and S.

$S_1$ = Projected jurisdictional kilowatt-hour sales for the period covered by the fuel costs included in E.

The appropriate revenue-related tax factor is to be included in these calculations.

The fuel cost F as determined by SCPSC Order No. 2006-554 for the period October 2006 through September 2007 is 1.7760 cents per kilowatt-hour.

# ADJUSTMENT FOR FUEL COSTS

## APPLICABILITY

This adjustment is applicable to and is a part of the Utility's South Carolina retail electric rate schedules.

The Public Service Commission has determined that the costs of Fuel in an amount to the nearest one ten-thousandth of a cent, as determined by the following formula, will be included in the base rates to the extent determined reasonable and proper by the Commission.

$$F = E / S + G / S_1$$

Where:

F = Fuel cost per kilowatt-hour included in base rate, rounded to the nearest one ten-thousandth of a cent.

E = Total Projected system Fuel costs:

(A) Fuel consumed in the Utility's own plants and the Utility's share of fuel consumed in jointly owned or leased plants. The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees plus SO2 emission allowances recorded in Account 509. The cost of nuclear fuel shall be that as shown in Account 518 excluding rental payments on leased nuclear fuel and except that, if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account.

**Plus**

(B) Fuel costs related to purchased power (and applicable SO2 emission allowances) such as those incurred in unit power and limited term power purchases where the fossil fuel costs and applicable SO2 emission allowances associated with energy purchased are identifiable and are identified in the billing statement. Also the cost of 'firm generation capacity purchases' which are defined as purchases made to cure a capacity deficiency or to maintain adequate reserve levels. "Costs of firm generation capacity purchases" include the total delivered costs of firm generation capacity purchased and excludes generation capacity reservation charges, generation capacity option charges and any other capacity charges.

**Plus**

(C) Fuel costs related to purchased power (including transmission charges and applicable SO2 emission allowances), such as short term, economy and other such purchases, where the energy is purchased on an economic dispatch basis, including the total delivered cost of economy purchases of electric power defined as purchases made to displace higher cost generation at a cost which is less than the purchasing utility's avoided variable costs for the generation of an equivalent quantity of electric power. Energy receipts that do not involve money payments such as Diversity energy and payback of storage energy are not defined as purchased or interchange power relative to this fuel calculation.

**Minus**

(D) The cost of fuel and applicable $SO_2$ emission allowances recovered through intersystem sales including the fuel costs and applicable $SO_2$ emission allowances related to economy energy sales and other energy sold on an economic dispatch basis.
Energy deliveries that do not involve billing transactions such as Diversity energy and payback of storage energy are not defined as sales relative to this fuel calculation.

S = Projected system kilowatt-hour sales excluding any intersystem sales.

G = Cumulative difference between jurisdictional fuel revenues billed and fuel expenses at the end of the month preceding the projected period utilized in E and S.

$S_1$ = Projected jurisdictional kilowatt-hour sales for the period covered by the fuel costs included in E.

The appropriate revenue-related tax factor is to be included in these calculations.

The fuel cost F as determined by SCPSC Order No. 2005-488 for the period October 2005 through September 2006 is 1.5802 cents per kilowatt-hour. The fuel cost will be further adjusted by a deferred tax decrement rider of 0.1732 cents per kilowatt-hour for a net billing factor of 1.4070 cents per kilowatt-hour for the period October 2005 through September 2006.