# Tariffs

January 1, 2020

Approved by the Nova Scotia Utility and Review Board pursuant to The Public Utilities Act, R.S.N.S., 189,c.380 as amended

For more information, call Nova Scotia Power at 1-800-428-6230 (902-428-6230 in Metro Halifax) www.nspower.ca

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View the complete Open Access Transmission Tariff on OASIS at:

http://oasis.nspower.ca/en/home/oasis/default.aspx

**CUSTOMER CHARGE**

$10.83 per month.

**ENERGY CHARGE**

| | Cents per kilowatt hour |
|---|---|
| Effective January 1, 2020 | 17.709 |
| Effective January 1, 2021 | 16.008 |
| Effective January 1, 2022 | 16.215 |

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge shall be $10.83.

**AVAILABILITY:**

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

**Optional Green Power Rider**

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service rate.

**Special Terms and Provisions**

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

*DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)*
Rate Code 05, 06 **Page 1 of 2**

## CUSTOMER CHARGE

$18.82 per month

## ENERGY CHARGES

| | December, January and February | | | |
|---|---|---|---|---|
| | **7:00 am to 12:00 pm** | **12:00 pm to 4:00 pm** | **4:00 pm to 11:00 pm** | **11:00 pm to 7:00 am** |
| | **Cents per kilowatt hour** | | | |
| Effective January 1, 2020 | 22.067 | 17.709 | 22.067 | 10.782 |
| Effective January 1, 2021 | 20.366 | 16.008 | 20.366 | 9.081 |
| Effective January 1, 2022 | 20.573 | 16.215 | 20.573 | 9.288 |

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am.

| | March to November | |
|---|---|---|
| | **7:00 am to 11:00 pm** | **11:00 pm to 7:00 am** |
| | **Cents per kilowatt hour** | |
| Effective January 1, 2020 | 17.709 | 10.782 |
| Effective January 1, 2021 | 16.008 | 9.081 |
| Effective January 1, 2022 | 16.215 | 9.288 |

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am.

## FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

## MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $18.82.

## AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the Domestic Service Time Of Day Tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

**CUSTOMER CHARGE**

$12.65 per month

**ENERGY CHARGE**

| | Cents per kilowatt hour | |
|---|---|---|
| | **For the first 200 kilowatt hours per month** | **For all additional kilowatt hours** |
| Effective January 1, 2020 | 18.098 | 16.284 |
| Effective January 1, 2021 | 16.416 | 14.602 |
| Effective January 1, 2022 | 16.483 | 14.669 |

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge shall be $12.65.

**AVAILABILITY:**

This tariff is applicable to electric energy for use where the annual consumption is less than 32,000 kWh per year and for which no other rates are applicable, and is available to customers on the General tariff where the annual consumption is less than 45,000 kWh per year.

For customers that elect to take service under the Small General tariff, where the General tariff is otherwise applicable, the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

**DEMAND CHARGE**

$10.497 per month per kilowatt of maximum demand.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

**ENERGY CHARGE**

| | **Cents per kilowatt hour** | |
|---|---|---|
| | **For the first 200 kilowatt hours per month per kilowatt of maximum demand** | **For all additional kilowatt hours** |
| Effective January 1, 2020 | 13.732 | 10.453 |
| Effective January 1, 2021 | 12.545 | 9.266 |
| Effective January 1, 2022 | 12.820 | 9.541 |

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MAXIMUM PER KWH CHARGE/MINIMUM BILL**

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

**AVAILABILITY:**

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh, or greater and for which no other rates are applicable.

For General tariff customers eligible for the Small General tariff the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

**SPECIAL CONDITIONS:**

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

**DEMAND CHARGE**

$13.345 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

**ENERGY CHARGE**

| | **Cents per kilowatt hour** |
|---|---|
| Effective January 1, 2020 | 9.916 |
| Effective January 1, 2021 | 9.526 |
| Effective January 1, 2022 | 9.526 |

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge shall be $12.65.

**AVAILABILITY:**

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over.

**SPECIAL CONDITIONS:**

(1) Metering will normally be at the low voltage side of the substation.

Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustments to the metered kWh usage will be made under the following conditions:

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by 1.75%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by 1.75%.

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2,000 kVA or 1,800 kW.

(3) The Company reserves the right to have a separate service and/or operating agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

## DEMAND CHARGE

$7.714 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

## ENERGY CHARGE

| | Cents per kilowatt hour | |
|---|---|---|
| | **For the first 200 kilowatt hours per month per kilovolt ampere of maximum demand** | **For all additional kilowatt hours** |
| Effective January 1, 2020 | 12.578 | 10.195 |
| Effective January 1, 2021 | 11.427 | 9.044 |
| Effective January 1, 2022 | 11.683 | 9.300 |

## FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

## MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

## AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kVA or 225 kW.

## SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering.

Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

## DEMAND CHARGE

$12.501 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

## ENERGY CHARGE

| | Cents per kilowatt hour |
|---|---|
| Effective January 1, 2020 | 8.555 |
| Effective January 1, 2021 | 8.672 |
| Effective January 1, 2022 | 9.000 |

## FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

## MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

## AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kVA (225 kW) and over, and for which no other rates are applicable.

## SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kVA (225 kW).

**DEMAND CHARGE**

$11.995 per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer

**ENERGY CHARGE**

| | Cents per kilowatt hour | |
|---|---|---|
| | **Firm customers** | **Interruptible customers** |
| Effective January 1, 2020 | 8.690 | 8.349 |
| Effective January 1, 2021 | 8.987 | 8.576 |
| Effective January 1, 2022 | 9.333 | 8.889 |

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

**AVAILABILITY:**

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

**SPECIAL CONDITIONS:**

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's

requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 2 000 kVA or 1,800 kW after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

**INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF** (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

**AVAILABILITY:**

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

(2) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the Company will exercise the automated control of the customer's load to interrupt the customer load.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in

the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

**SPECIAL CONDITIONS:**

(1) The Company reserves the right to have a separate service agreement if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

**DEMAND CHARGE**

$12.445 per month per kilovolt ampere of the higher of:

(a) maximum actual demand of the current month or

(b) the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months but excluding the actual monthly peak demands recorded during the first two hours following restoration of any outage of at least one hour in duration. In this circumstance, the next highest monthly peak demand, registered outside of the restoration period, will be used. Customers will make reasonable efforts to manage post-restoration demand peaks.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

**ENERGY CHARGE**

| | **Cents per kilowatt hour** |
|---|---|
| Effective January 1, 2020 | 9.746 |
| Effective January 1, 2021 | 9.171 |
| Effective January 1, 2022 | 9.534 |

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**AVAILABILITY:**

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

*OUTDOOR RECREATIONAL LIGHTING TARIFF*
**Rate Code 41** 

## ENERGY CHARGE

| | Cents per kilowatt hour |
|---|---|
| Effective January 1, 2020 | 18.225 |
| Effective January 1, 2021 | 16.717 |
| Effective January 1, 2022 | 17.060 |

## FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

## AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

## (A) STREET AND AREA LIGHTING

**AVAILABILITY:**

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in Cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**RATES**

**(1) INCANDESCENT**

a) Operating, Maintenance and Capital (Full Charge)

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| **Rate Code** | **Watts** | **kWh/Month.** | **2020** | **2021** | **2022** | |
| 001 | 300 and less | 97 | 24.47 | 23.01 | 23.34 | |
| 002 | Greater than 300 | 154 | 34.83 | 32.51 | 33.04 | |

b) Operating Only

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| **Rate Code** | **Watts** | **kWh/Month.** | **2020** | **2021** | **2022** | |
| 003 | 300 and Less | 97 | 17.43 | 15.97 | 16.30 | |

## (2) MERCURY VAPOUR

a) Operating, Maintenance and Capital (Full Charge)

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 100 | 100 | 43 | 16.10 | 15.45 | 15.60 | |
| 101 | 125 | 52 | 19.22 | 18.43 | 18.61 | |
| 102 | 175 | 69 | 20.51 | 19.47 | 19.71 | |
| 103 | 250 | 97 | 26.28 | 24.82 | 25.15 | |
| 104 | 400 | 154 | 36.60 | 34.28 | 34.81 | |
| 105 | 700 | 260 | 56.84 | 52.92 | 53.81 | |
| 106 | 1000 | 363 | 76.38 | 70.91 | 72.16 | |
| 107 | 250 | 212 | 44.91 | 41.71 | 42.44 | Continuous Operation |

b) Operating and Maintenance Only

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 201 | 125 | 52 | 16.21 | 15.42 | 15.60 | |
| 202 | 175 | 69 | 17.54 | 16.50 | 16.74 | |
| 203 | 250 | 97 | 22.59 | 21.13 | 21.46 | |
| 204 | 400 | 154 | 32.83 | 30.51 | 31.04 | |
| 205 | 700 | 260 | 51.89 | 47.97 | 48.86 | |
| 206 | 1000 | 363 | 70.40 | 64.93 | 66.18 | |

c) Operating Only

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 301 | 125 | 52 | 9.34 | 8.55 | 8.73 | |
| 302 | 175 | 69 | 12.38 | 11.34 | 11.58 | |
| 303 | 250 | 97 | 17.43 | 15.97 | 16.30 | |
| 304 | 400 | 154 | 27.67 | 25.35 | 25.88 | |
| 305 | 700 | 260 | 46.73 | 42.81 | 43.70 | |
| 306 | 1000 | 363 | 65.24 | 59.77 | 61.02 | |

## (3) FLUORESCENT

a) Operating, Maintenance and Capital (Full Charge)

| Rate Code | Bulb Length | Number of Bulbs/Unit | kWh/Mo. | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|---|
| | | | | 2020 | 2021 | 2022 | |
| 110 | 24 | 2 | 30 | 18.14 | 17.69 | 17.79 | |
| 111 | 48 | 2 | 85 | 28.28 | 27.00 | 27.29 | |
| 112 | 72 | 2 | 116 | 34.33 | 32.58 | 32.98 | |
| 113 | 72 | 4 | 222 | 54.49 | 51.14 | 51.91 | |
| 114 | 96 | 1 | 47 | 21.72 | 21.01 | 21.17 | |
| 115 | 72 | 1 | 60 | 23.67 | 22.77 | 22.98 | |
| 116 | 48 | 4 | 166 | 43.42 | 40.91 | 41.48 | |

b) Operating and Maintenance Only

| Rate Code | Bulb Length | Number of Bulbs/Unit | kWh/Mo. | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|---|
| | | | | 2020 | 2021 | 2022 | |
| 213 | 72 | 4 | 222 | 50.19 | 46.84 | 47.61 | |
| 214 | 96 | 1 | 47 | 18.75 | 18.04 | 18.20 | |
| 215 | 72 | 1 | 60 | 21.09 | 20.19 | 20.40 | |
| 216 | 48 | 4 | 166 | 40.17 | 37.66 | 38.23 | |
| 217 | 48 | 1 | 49 | 19.10 | 18.36 | 18.53 | |
| 218 | 48 | 2 | 85 | 25.59 | 24.31 | 24.60 | |

c) Operating Only

| Rate Code | Bulb Length | Number of Bulbs/Unit | kWh/Mo. | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|---|
| | | | | 2020 | 2021 | 2022 | |
| 330 | 35 | 4 | 47 | 8.44 | 7.73 | 7.89 | |

## (4) FLUORESCENT CROSSWALK

a) Continuous Burning - Operating Only

| Rate Code | Bulb Length | Number of Bulbs/Unit | kWh/Mo. | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|---|
| | | | | 2020 | 2021 | 2022 | |
| 117 | 72 | 4 | 486 | 70.84 | 63.51 | 65.18 | |
| 118 | 24 | 2 | 66 | 9.61 | 8.62 | 8.84 | |
| 119 | 48 | 4 | 364 | 53.07 | 47.59 | 48.83 | |
| 120 | 96 | 2 | 254 | 37.04 | 33.21 | 34.08 | |
| 150 | 96 | 4 | 613 | 89.36 | 80.12 | 82.22 | |

b) Photocell Operation - Operating Only

| Rate Code | Bulb Length | Number of Bulbs/Unit | kWh/Mo. | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|---|
| | | | | 2020 | 2021 | 2022 | |
| 310 | 24 | 2 | 30 | 5.28 | 5.00 | 5.12 | |
| 311 | 48 | 4 | 166 | 29.20 | 27.61 | 28.31 | |
| 312 | 72 | 2 | 116 | 20.41 | 19.30 | 19.79 | |
| 313 | 72 | 4 | 222 | 39.00 | 36.88 | 37.81 | |
| 314 | 96 | 1 | 47 | 8.25 | 7.80 | 8.00 | |
| 315 | 72 | 1 | 60 | 10.55 | 9.97 | 10.23 | |
| 350 | 96 | 4 | 280 | 49.22 | 46.55 | 47.73 | |

## (5) LOW PRESSURE SODIUM

a) Operating, Maintenance and Capital (Full Charge)

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 130 | 135 | 60 | 32.04 | 31.14 | 31.35 | |
| 131 | 180 | 80 | 38.23 | 37.02 | 37.30 | |
| 132 | 90 | 45 | 29.34 | 28.66 | 28.81 | |

b) Operating and Maintenance Only

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 231 | 180 | 80 | 29.85 | 28.64 | 28.92 | |

c) Operating Only

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 331 | 180 | 80 | 14.38 | 13.17 | 13.45 | |

## (6) HIGH PRESSURE SODIUM

| Rate Code | Watts | kWh/Mo. | Per Month ($) 2020 | 2021 | 2022 | Other |
|---|---|---|---|---|---|---|
| 121 | 250 | 100 | 25.95 | 24.99 | 25.41 | |
| 122 | 400 | 150 | 34.86 | 33.42 | 34.05 | |
| 123 | 70 | 32 | 13.79 | 13.49 | 13.62 | |
| 124 | 100 | 45 | 16.10 | 15.67 | 15.86 | |
| 125 | 150 | 65 | 19.80 | 19.18 | 19.46 | |
| 126 | 100 | 99 | 27.38 | 26.43 | 26.85 | Continuous Operation |

b) Operating and Maintenance Only

| Rate Code | Watts | kWh/Mo. | Per Month ($) 2020 | 2021 | 2022 | Other |
|---|---|---|---|---|---|---|
| 221 | 250 | 100 | 23.13 | 21.63 | 21.97 | |
| 222 | 70 | 32 | 10.90 | 10.42 | 10.53 | |
| 223 | 100 | 45 | 13.24 | 12.56 | 12.71 | |
| 224 | 150 | 65 | 16.84 | 15.86 | 16.09 | |

c) Operating Only

| Rate Code | Watts | kWh/Mo. | Per Month ($) 2020 | 2021 | 2022 | Other |
|---|---|---|---|---|---|---|
| 321 | 250 | 100 | 17.97 | 16.47 | 16.81 | |
| 322 | 70 | 32 | 5.74 | 5.26 | 5.37 | |
| 323 | 100 | 45 | 8.08 | 7.40 | 7.55 | |
| 324 | 150 | 65 | 11.68 | 10.70 | 10.93 | |
| 326 | 400 | 150 | 26.96 | 24.70 | 25.21 | |
| 327 | 500 | 183 | 32.90 | 30.14 | 30.77 | |
| 328 | 1000 | 363 | 65.25 | 59.78 | 61.03 | |
| 329 | 1500 | 500 | 89.87 | 82.33 | 84.04 | |

## (7) METALLIC ADDITIVE

a) Operating, Maintenance and Capital (Full Charge)

| Rate Code | Watts | kWh/Mo. | Per Month ($) 2020 | 2021 | 2022 | Other |
|---|---|---|---|---|---|---|
| 140 | 400 | 150 | 39.02 | 36.76 | 37.27 | |
| 141 | 1000 | 360 | 82.65 | 77.22 | 78.45 | |
| 142 | 250 | 100 | 34.09 | 32.59 | 32.93 | |
| 143 | 150 | 67 | 28.15 | 27.14 | 27.37 | |
| 144 | 100 | 50 | 25.11 | 24.35 | 24.52 | |

b) Operating Only

| Rate Code | Watts | kWh/Mo. | Per Month ($) 2020 | 2021 | 2022 | Other |
|---|---|---|---|---|---|---|
| 341 | 1000 | 360 | 64.71 | 59.28 | 60.51 | |
| 342 | 400 | 150 | 26.96 | 24.70 | 25.21 | |
| 343 | 250 | 100 | 17.97 | 16.47 | 16.81 | |
| 344 | 175 | 75 | 13.48 | 12.35 | 12.61 | |
| 345 | 150 | 67 | 12.03 | 11.02 | 11.25 | |
| 346 | 100 | 50 | 8.99 | 8.23 | 8.40 | |

## (8) LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 530 | 4.6 | 2 | 0.36 | 0.33 | 0.34 | Non-Continuous |
| 531 | 7.5 | 5 | 0.73 | 0.65 | 0.67 | Continuous |

## (9) LIGHT EMITTING DIODE (LED) – Operating Only

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 532 | 44 | 15 | 2.70 | 2.47 | 2.52 | |
| 533 | 66 | 22 | 3.95 | 3.62 | 3.70 | |
| 534 | 88 | 29 | 5.21 | 4.78 | 4.87 | |
| 535 | 92 | 31 | 5.57 | 5.10 | 5.21 | |
| 536 | 105 | 35 | 6.29 | 5.76 | 5.88 | |
| 537 | 170 | 57 | 10.25 | 9.39 | 9.58 | |
| 539 | 110 | 37 | 6.65 | 6.09 | 6.22 | |
| 540 | 65 | 22 | 3.95 | 3.62 | 3.70 | |
| 541 | 55 | 18 | 3.24 | 2.96 | 3.03 | |
| 542 | 83 | 28 | 5.03 | 4.61 | 4.71 | |
| 543 | 48 | 16 | 2.88 | 2.63 | 2.69 | |
| 544 | 72 | 24 | 4.31 | 3.95 | 4.03 | |

## (10) LIGHT EMITTING DIODE (LED) – Operating & Capital Only (full charge)

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| Rate Code | Watts | kWh/Mo. | 2020 | 2021 | 2022 | |
| 615 | 44 | 15 | 9.88 | 9.65 | 9.70 | |
| 616 | 55 | 18 | 10.42 | 10.14 | 10.21 | |
| 623 | 28 | 9 | 8.80 | 8.66 | 8.69 | |
| 624 | 50 | 17 | 10.24 | 9.98 | 10.04 | |
| 625 | 72 | 24 | 11.49 | 11.13 | 11.21 | |
| 626 | 100 | 33 | 13.11 | 12.61 | 12.73 | |
| 627 | 200 | 67 | 19.22 | 18.21 | 18.44 | |

**(11) LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)**

| | | | Per Month ($) | | | Other |
|---|---|---|---|---|---|---|
| **Rate Code** | **Watts** | **kWh/Mo.** | **2020** | **2021** | **2022** | |
| 724 | 55 | 18 | 10.35 | 10.07 | 10.14 | |
| 740 | 190 | 63 | 24.79 | 23.84 | 24.06 | |
| 741 | 261 | 87 | 30.84 | 29.53 | 29.82 | |
| 742 | 124 | 41 | 17.98 | 17.36 | 17.50 | |
| 743 | 84 | 28 | 14.96 | 14.54 | 14.64 | |

## (B) MISCELLANEOUS LIGHTING

### DEMAND CHARGE

$11.777 per month per kilowatt of connected load.

### ENERGY CHARGE

| | Cents per kilowatt hour | |
|---|---|---|
| | **For the first 200 kilowatt hours per month per kilowatt of maximum demand** | **For all additional kilowatt hours** |
| Effective January 1, 2020 | 16.251 | 11.725 |
| Effective January 1, 2021 | 14.743 | 10.217 |
| Effective January 1, 2022 | 15.086 | 10.560 |

### FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MAXIMUM PER KWH CHARGE/MINIMUM BILL**

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $17.51 per month if such unmetered service is billed separately from any metered account.

**CAPITAL CHARGE:** (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

**MAINTENANCE CHARGE:** (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

**AVAILABILITY:**

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided for under the Street and Area Lighting rate.

**(C) MISCELLANEOUS SMALL LOADS**

**DEMAND CHARGE**

$11.777 per month per kilowatt of connected load.

**ENERGY CHARGE**

| | Cents per kilowatt hour | |
|---|---|---|
| | **For the first 200 kilowatt hours per month per kilowatt of maximum demand** | **For all additional kilowatt hours** |
| Effective January 1, 2020 | 16.251 | 11.725 |
| Effective January 1, 2021 | 14.743 | 10.217 |
| Effective January 1, 2022 | 15.086 | 10.560 |

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kWh per month and will be rounded to hundredths of a cent in its application.

**FUEL ADJUSTMENT MECHANISM (FAM)**

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

**MAXIMUM PER KWH CHARGE/MINIMUM BILL**

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall be $17.51 per month if such unmetered service is billed separately from any metered account.

**AVAILABILITY:**

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals, etc.

## APPLICABILITY:

This schedule is a mandatory rider to all electric rate schedules, except the following tariffs: Generation Replacement and Load Following, Extra High Voltage Time-of-Use Real Time Pricing, High Voltage Time-of-Use Real Time Pricing, Distribution Voltage Time-of-Use Real Time Pricing. FAM adjustments will apply to the Standard Energy Charge of the Extra Large Industrial 2P-RTP tariff. FAM adjustments will apply to Additional Energy supplied under the Mersey System Agreement when Additional Energy is priced at a tariff to which FAM adjustments apply.

## FUEL ADJUSTMENT:

The applicable charges for electric service to the Company's retail and municipal customers shall be increased or decreased to the nearest 0.001 cents per kWh to recover or credit the difference in actual fuel cost from the costs in base rates in accordance with the following rate class-specific formula:

**Fuel Adjustment Rider = AA + BA**

Where:

"AA" is a rate class-specific Actual Adjustment which is the difference between fuel-related costs recovered from a rate class through the application of the base rates during the previous calendar year and the actual Fuel Costs incurred and allocated to the rate class for the same time period. The actual fuel costs will include the same cost items as base fuel costs.

"BA" is a rate class-specific Balance Adjustment which accounts for any over- or under-collections which have occurred as a result of prior adjustments.

SPECIAL CONDITIONS:

(1) Base Cost of Fuel

The Base Cost of Fuel can be re-set in a General Rate Application or, absent a General Rate Application, every second year as part of the FAM adjustment process. Changes in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the then-current Board-approved Cost of Service Methodology.

(2) Incentive

For a total fuel cost variance of up to $50 million dollars (Actual Fuel Costs - [(Actual Sales) x (Base Fuel Cost $/Mwh)] ), 90% of any savings or increase in cost will be credited or charged to customers. The portion of any variance that is in excess of $50 million dollars will be fully applied in the calculation of the "AA". Credits or charges will be applied to the energy component of rates on a cents per kWh basis.

(3) Load Migration to non-FAM classes

When a customer transitions its load, whether in whole or in part, from a FAM class to a non-FAM class, NS Power shall determine the outstanding fuel cost imbalance of the customer at the time of transition. This determined imbalance will be adjusted as necessary in future FAM proceedings concerned with apportionment of fuel costs incurred in the period in question. The adjustments will be subject to UARB approval. The outstanding imbalance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB.

The applicable charges by rate class are as follows.

| | **Effective January 1, 2020** | | |
|---|---|---|---|
| **Rate Class** | **Actual Adjustment (AA) in cents per kWh** | **Balance Adjustment (BA) in cents per kWh** | **FAM AA/BA Combined in cents per kWh** |
| **Domestic Service** | 0.057 | (1.961) | (1.904) |
| **Domestic Service Time of Day** | 0.057 | (1.961) | (1.904) |
| **Small General** | (0.071) | (1.677) | (1.748) |
| **General** | 0.250 | (1.706) | (1.456) |
| **Large General** | (0.331) | (0.059) | (0.390) |
| **Small Industrial** | 0.201 | (1.603) | (1.402) |
| **Medium Industrial** | 0.625 | (0.827) | (0.202) |
| **Large Industrial Firm** | 0.551 | (0.589) | (0.038) |
| **Large Industrial Interruptible** | 0.551 | (0.628) | (0.077) |
| **Municipal** | 0.235 | (1.162) | (0.927) |
| **Unmetered** | 0.512 | (2.357) | (1.845) |

| | Effective January 1, 2021 | | |
|---|---|---|---|
| **Rate Class** | **Actual Adjustment (AA) in cents per kWh** | **Balance Adjustment (BA) in cents per kWh** | **FAM AA/BA Combined in cents per kWh** |
| **Domestic Service** | 0.000 | 0.000 | 0.000 |
| **Domestic Service Time of Day** | 0.000 | 0.000 | 0.000 |
| **Small General** | 0.000 | 0.000 | 0.000 |
| **General** | 0.000 | 0.000 | 0.000 |
| **Large General** | 0.000 | 0.000 | 0.000 |
| **Small Industrial** | 0.000 | 0.000 | 0.000 |
| **Medium Industrial** | 0.000 | 0.000 | 0.000 |
| **Large Industrial Firm** | 0.000 | 0.000 | 0.000 |
| **Large Industrial Interruptible** | 0.000 | 0.000 | 0.000 |
| **Municipal** | 0.000 | 0.000 | 0.000 |
| **Unmetered** | 0.000 | 0.000 | 0.000 |

| | Effective January 1, 2022 | | |
|---|---|---|---|
| **Rate Class** | **Actual Adjustment (AA) in cents per kWh** | **Balance Adjustment (BA) in cents per kWh** | **FAM AA/BA Combined in cents per kWh** |
| **Domestic Service** | 0.000 | 0.000 | 0.000 |
| **Domestic Service Time of Day** | 0.000 | 0.000 | 0.000 |
| **Small General** | 0.000 | 0.000 | 0.000 |
| **General** | 0.000 | 0.000 | 0.000 |
| **Large General** | 0.000 | 0.000 | 0.000 |
| **Small Industrial** | 0.000 | 0.000 | 0.000 |
| **Medium Industrial** | 0.000 | 0.000 | 0.000 |
| **Large Industrial Firm** | 0.000 | 0.000 | 0.000 |
| **Large Industrial Interruptible** | 0.000 | 0.000 | 0.000 |
| **Municipal** | 0.000 | 0.000 | 0.000 |
| **Unmetered** | 0.000 | 0.000 | 0.000 |

*GENERATION REPLACEMENT AND LOAD FOLLOWING TARIFF*

## SERVICE DEFINITION

Service under this tariff consists in delivery of supplemental power to partial requirement customers who operate their own dispatchable generation equipment, as approved to be connected to the grid by the Company. The Service has three components.

**Generation Replacement Service** - Backup supply of power on a best efforts basis where the customer's generation equipment is removed from service due to scheduled maintenance, forced outage, or loss of fuel supply.

**Optional Load Following Service** – Energy delivery in respect of imbalance between load and generation where customer's generation falls in any given hour below the lower of the established net operating capability or customer's load. Energy delivery under this service is defined as top-up energy.

**Spill Service** - Hourly generation in excess of the customer's load absorbed by the Company. This excess energy is defined as spilled energy.

Power supplied by the Company to the customer in any given hour above the customer generation, if not below the established net operating capability, is defined as supplementary power and will be billed under applicable full requirement tariff. Customers taking this service will be referred to as "customer-generators".

## RATE

Backup Service:

The actual or estimated average time coincident incremental cost of generation including transmission losses for the period service is provided plus 0.500 cents per kWh for additional Operating and Maintenance costs, service charges and Administration & General compensation.

Optional Generation Load Following:

Average incremental cost of generation expressed in cents per kWh as determined by the generation forecast for the rate year plus add on charges as defined for back-up service. This price will be 6.775 cents per kWh.

***GENERATION REPLACEMENT AND LOAD FOLLOWING TARIFF***

## ENERGY CREDIT

The Energy Credit is equal to the average incremental cost of generation as defined under Optional Generation Load Following.

## AVAILABILITY

This tariff is available to:

(a) Customers who have their own qualifying generating facility of not less than 2,000 kW of aggregate capacity, as defined under Special Condition (8), normally used to support their own load;

(b) Energy supplied to Non-Utility Owned Generation sites for purposes of startup and replacement of energy normally supplied from their own generation, where the customer has signed an operating agreement under this tariff schedule.

The following general terms and conditions will apply to the applications.

(1) Energy under the Generation Replacement Service provision will be supplied upon request by the customer. In cases where advance written notification can be given by the customer, such as planned maintenance, the Company will advise the customer in writing of the quoted price which will be based on estimated costs during the period. In an emergency situation where time does not permit advance notification the price will be based upon actual costs until the customer provides written notification of the duration of the taking following which the Company will advise the customer in writing of the quoted price for the remainder of the period.

Energy under the load following section will be supplied either through on-going communication provision such as telemetering (when load fluctuations are involved) or written requests (where application is to a specific level of load).

***GENERATION REPLACEMENT AND LOAD FOLLOWING TARIFF***

(2) In the event there is an interruption required by NS Power in order to avoid shortfalls in electric supply, customers taking energy under the Generation Replacement Service or Load Following Service will be the first to be called upon to interrupt energy usage from NS Power.

(3) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(4) Customers must install metering equipment to monitor the output of the customer's generation. The equipment and installation must be approved by the Company and the costs will be the responsibility of the customer.

**SPECIAL CONDITIONS**

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation.

Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Any service requirements beyond those provided by a single step-down transformation from transmission voltage must be borne by the customer. The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(5) The Company reserves the right to determine the metering location.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.75% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

| Power Factor | Constant | Power Factor | Constant |
|---|---|---|---|
| 90-100% | 1.0000 | 65-70% | 1.1255 |
| 80-90% | 1.0230 | 60-65% | 1.1785 |
| 75-80% | 1.0500 | 55-60% | 1.2455 |
| 70-75% | 1.0835 | 50-55% | 1.3335 |

(8) Qualifying generating facility must meet the following requirements:

(i.) Utilize dispatchable sources of generation.

(ii.) May have more than one generating unit so long as the aggregate manufacturer's nameplate rating is of not less than 2,000 kilowatts and which NSPI has the right to verify through inspection or testing.

(iii.) At the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NS Power or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

(iv.) Generating facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's interconnection guidelines.

## GENERATION LOAD FOLLOWING CRITERIA

(1) Two months preceding each tariff year the customer-generator, in conjunction with the Company, shall establish the aggregate net operating capability of its generation equipment for the billing purposes of calculating hourly top-up energy from NS Power during the next tariff year. The net operating capability will be set based upon tests of customer's generation equipment and/or operating records. During a period during which the customer-generator encounters conditions that will result in a temporary significant reduction in generation below the established net operating capability, bill payments under the Load Following service and the other full requirement rate, if applicable, will be set based on adjusted net operating capability reflecting the average generation level during such period. For each billing month of the tariff year the Company will load follow to the equivalent of one hundred (100) percent load factor of the adjusted net operating capability in each hour that the customer generation does not exceed its adjusted net operating capability.

(2) On or before November 7th preceding each tariff year the Company shall apply to the Nova Scotia Utility and Review Board for approval of its forecasted incremental cost of generation for the following tariff year. Such average forecasted incremental cost shall be included in determining the load following rate for the next tariff year and each affected customer shall be notified.

## *ONE PART EXTRA HIGH VOLTAGE REAL TIME PRICING TARIFF*

### DEMAND CHARGE

NIL

### ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00am - 11:00pm, non-holiday weekdays): 6.802 ¢/kWh
Off-peak (11:00pm - 7:00am, non-holiday weekdays): 0.509 ¢/kWh
Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Utility and Review Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

### AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 138 kV or higher and have loads of 2000 KVA or 1800 KW, and over.

### SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

***ONE PART EXTRA HIGH VOLTAGE REAL TIME PRICING TARIFF***

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.75% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause (1), but agrees to remain interruptible for up to five years as provided for under Availability Clause (5) of the Large Industrial Tariff Interruptible Rider. Within the five year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

| POWER FACTOR | CONSTANT | POWER FACTOR | CONSTANT |
|---|---|---|---|
| 90-100% | 1.0000 | 65-70% | 1.1255 |
| 80-90% | 1.0230 | 60-65% | 1.1785 |
| 75-80% | .0500 | 55-60% | 1.2455 |
| 70-75% | 1.0835 | 0-55% | 1.3335 |

(8) The Company reserves the right to have a separate service agreement, if in the opinion of

***ONE PART EXTRA HIGH VOLTAGE REAL TIME PRICING TARIFF***

the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

## *ONE PART HIGH VOLTAGE REAL TIME PRICING TARIFF*

### DEMAND CHARGE

NIL

### ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00am - 11:00pm, non-holiday weekdays): 7.353 ¢/kWh
Off-peak (11:00pm - 7:00am, non-holiday weekdays): 0.769 ¢/kWh
Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Utility and Review Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

### AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 69 kV and have loads of 2000 KVA or 1800 KW, and over.

### SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

## *ONE PART HIGH VOLTAGE REAL TIME PRICING TARIFF*

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.75% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause (1), but agrees to remain interruptible for up to five years as provided for under Availability Clause (5) of the Large Industrial Tariff Interruptible Rider. Within the five year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

***ONE PART HIGH VOLTAGE REAL TIME PRICING TARIFF***

| POWER FACTOR | CONSTANT | POWER FACTOR | CONSTANT |
|---|---|---|---|
| 90-100% | 1.0000 | 65-70% | 1.1255 |
| 80-90% | 1.0230 | 60-65% | 1.1785 |
| 75-80% | 1.0500 | 55-60% | 1.2455 |
| 70-75% | 1.0835 | 50-55% | 1.3335 |

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

*ONE PART DISTRIBUTION VOLTAGE REAL TIME PRICING TARIFF*

## DEMAND CHARGE

NIL

## ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00am - 11:00pm, non-holiday weekdays): 7.483¢/kWh
Off-peak (11:00pm - 7:00am, non-holiday weekdays): 1.834¢/kWh
Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Utility and Review Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

## AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at voltage less than 69 KV and have loads of 2000 KVA or 1800 KW, and over.

## SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

## *ONE PART DISTRIBUTION VOLTAGE REAL TIME PRICING TARIFF*

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.75% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause (1), but agrees to remain interruptible for up to five years as provided for under Availability Clause (5) of the Large Industrial Tariff Interruptible Rider. Within the five year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

***ONE PART DISTRIBUTION VOLTAGE REAL TIME PRICING TARIFF***

| POWER FACTOR | CONSTANT | POWER FACTOR | CONSTANT |
|---|---|---|---|
| 90-100% | 1.0000 | 65-70% | 1.1255 |
| 80-90% | 1.0230 | 60-65% | 1.1785 |
| 75-80% | 1.0500 | 55-60% | 1.2455 |
| 70-75% | 1.0835 | 50-55% | 1.3335 |

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

*SHORE POWER TARIFF*

**AVAILABILITY**

(1) This tariff is available to port authorities of Nova Scotia for the sole purpose of providing port electricity to cruise ships docked in ports to meet their own consumption needs in displacement of the on-board self-generation. The tariff is applicable to electric energy where the regular demand is 2,000 kVA or 1,800 kW, and over.

(2) Customers served under this tariff must accept supply interruption. In the event there is an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

(i.) Generation Replacement and Load Following (GR&LF) Rate
(ii.) Load Retention Tariff
(iii.) Shore Power Tariff
(iv.) Interruptible Rider to the Large Industrial Rate

unless there are technical reasons to alter this sequence specific to the instance.

(3) This is a seasonal tariff available from April 1 to November 30.

**ENERGY CHARGE**

Energy charges will vary by voltage level of the point of delivery and will be made up of two components.

(1) Annually adjusted fuel cost component which shall be the Company's forecast average annual marginal energy cost as approved for use with the GR&LF tariff and adjusted for line losses at the voltage level of the point of delivery.

(2) A fixed cost adder adjusted concurrent with changes in base cost rates coming into effect as a result of a General Rate Case application.

***SHORE POWER TARIFF***

| Base Energy Charge Components | Transmission voltage of 138 kV or higher (cents per kWh) | Transmission voltage of 69 kV (cents per kWh) | Distribution voltage (cents per kWh) |
|---|---|---|---|
| Fuel Cost | 6.463 | 6.526 | 6.653 |
| Fixed Cost Adder | 4.280 | 4.469 | 5.255 |
| Total | 10.744 | 10.995 | 11.908 |

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer and the customer is served at a transmission voltage level.

**SUPPLY INTERRUPTIONS**

This is an interruptible service. Before connecting the ship to the shore supply the port authority will request permission from NSPI indicating the expected load and duration for which the power is needed.

The customer will make available suitable contact telephone numbers of a person or persons who are able to disconnect the load within ten minutes. Supply Interruption calls will be made to all customers taking energy under this tariff on an equitable and transparent basis.

This Tariff will be available provided that:

(1) The customer has provided written notice of its desire to take interruptible service.

(2) The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order and must have a designated staff person to answer the dedicated telephone at all times when cruise ships are connected to the utility grid. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rate.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty

charges. The penalty will apply based on the usage of the vessel being served via the Port Authority's equipment following the request to interrupt on the day on which the non-compliance took place.

Penalty for Non-Compliance

All energy served after the 10 minute deadline has expired will be billed at $5.00 per kWh. In addition a fixed charge of $2000.00 will be applied.

The penalty charge is applicable above and beyond the Port Authority's monthly bill.

**SPECIAL CONDITIONS**

(1) The Port Authority owns and is responsible for the maintenance and operation of all electrical equipment required for the supply of port electricity to docked ships other than the meters and metering transformers supplied by NSPI. NSPI owns and is responsible for the maintenance of meters and metering transformers installed on the Port Authority premises for the purposes of billing.

(2) The Port Authority will ensure that trained staff is available to operate on-shore interconnection equipment to facilitate the connection, synchronization, disconnection and interruption if needed at all times. Such operators must be available to be contacted by NSPI from a minimum of one hour before connection is required to the time that the ship returns to on board power supply.

(3) The Port Authority will file a two year schedule of expected vessels showing their peak electrical demand before October 31 in a calendar year preceding the cruise ship season.

(4) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(5) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.75% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90%

lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

| POWER FACTOR | CONSTANT | POWER FACTOR | CONSTANT |
|---|---|---|---|
| 90-100% | 1.0000 | 65-70% | 1.1255 |
| 80-90% | 1.0230 | 60-65% | 1.1785 |
| 75-80% | 1.0500 | 55-60% | 1.2455 |
| 70-75% | 1.0835 | 50-55% | 1.3335 |

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

***WHOLESALE MARKET BACKUP/TOP-UP SERVICE TARIFF***

## CUSTOMER CHARGE

The monthly customer charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of customers subscribed} * 12}$$

This charge will be $340.97 per month.

## DEMAND CHARGE

$5.286 per month, per kilowatt (kW) of billing demand measured on an average hourly basis.

Contracted firm demand requirement is defined as the demand (kW) requested by the wholesale customer (or aggregate customer group) and agreed to be supplied by NSPI. This may constitute all, or a portion of the demand contracted to be served on a primary basis by a third party supplier. Billing demand is determined based upon the following formula:

Billing demand = (PR * min(CD, CF * GC)) + (CD – min(CD, CF*GC))

Where: PR is Planning Reserve (based on NPCC planning criteria, i.e., 20% or as updated)
GC is the third party supplier's generating capacity

a) For non-dispatchable generation, GC = MSC, the Maximum Spill Capacity as defined in Wholesale Market Non-Dispatchable Supplier Spill Tariff.
b) For dispatchable generation, GC = the supplier's maximum capacity contracted to provide its wholesale customers' demand

CD is the customer's Contract Demand
CF is the capacity factor associated with the third party supplier's generation

## ENERGY CHARGE

The energy charge shall be the Company's forecast average annual marginal energy costs as approved for use with the GRLF rate.

## MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the customer charge plus the demand charge.

***WHOLESALE MARKET BACKUP/TOP-UP SERVICE TARIFF***

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## AVAILABILITY

The tariff is available to wholesale customers as defined in section 2(b) of the Electricity Act, Chapter 25 of the Acts of 2004.

> (b) "wholesale customer" means Nova Scotia Power Incorporated, the electric utilities of the towns of Antigonish, Berwick, Canso, Lunenburg and Mahone Bay and The Electric Light Commissioners for Riverport, in the County of Lunenburg.

The tariff is applicable to the *scheduled* backup\top-up load of participating customers under the following terms and conditions:

(1) The wholesale customer has provided written notice of its intent to take service under this tariff, clearly identifying the following:

   a. The Municipal utility or utilities for which service is being requested.
   b. The year for which service is being requested.
   c. The contract demand (kW) required for backup and top-up service.
   d. The portion of the customer's annual load contracted to be supplied by third party suppliers or through self-supply
   e. The names, addresses, contact details and supply arrangements associated with contracted third party suppliers

   Backup\top-up service will be subscribed on a minimum 12 month, annual-renewable basis. Applications for service must be provided annually to NSPI by January 31st of each year, for service applicable to the subsequent year.

(2) Adequate metering equipment, as dictated by the Generation Interconnection Agreement, must be installed to monitor the generation of any third-party generators selected for use by the wholesale customer. The equipment and installation must be approved by the Company and the costs will be the responsibility of the generator.

## SPECIAL CONDITIONS

(1) This tariff is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 69 kV or higher. For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings shall be increased by 1.75% for each transformation between the meter and the transmission voltage.

***WHOLESALE MARKET BACKUP/TOP-UP SERVICE TARIFF***

(2) The charges under this rate do not reflect transmission service costs. Customers taking service under this tariff must also take service under OATT.

(3) For system reasons, NSPI may, at its discretion, deny an application for service from a customer who has not taken service from NSPI in the year prior to the year requested.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

## *WHOLESALE MARKET NON-DISPATCHABLE SUPPLIER SPILL TARIFF*

**ADMINISTRATION CHARGE**

The monthly administration charge under this tariff is calculated according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{Forecast number of suppliers supplying wholesale customers } *12}$$

This charge will be $2,045.80 per month.

**ENERGY CREDIT**

Compensation for spill energy delivered to NSPI will be at the Company's forecast average annual marginal energy costs as approved for use with the GRLF rate.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge shall be the administration charge.

**AVAILABILITY**

This tariff is available for use by independent non-dispatchable electric generators serving customers taking service under the Wholesale Market Backup\top-up Service tariff. The tariff is applicable to *scheduled* "spill energy", under the following terms and conditions:

(1) "Spill energy" is defined as the scheduled hourly energy forecast to be produced by the supplier above the scheduled hourly energy requirement of their wholesale customer(s). Unscheduled energy produced will be compensated according to OATT imbalance guidelines. Spill compensation under this tariff is limited to the supplier's Maximum Spill Capacity (kW). Maximum Spill Capacity must be approved by NSPI prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating wholesale customer energy (MWh). Spill capacity will be reviewed periodically and adjusted as required to ensure that it matches the amount required to provide subscribed annual customer energy.

(2) Suppliers must install metering equipment to monitor the output of their generation. Consistent with the Generation Interconnection Agreement, the equipment and installation must be approved by the Company and the costs will be the responsibility of the supplier.

***WHOLESALE MARKET NON-DISPATCHABLE SUPPLIER SPILL TARIFF***

## SPECIAL CONDITIONS

(1) Suppliers must meet all conditions set forth in the Generation Interconnection Procedures and Generation Interconnection Agreement.

(2) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(3) The supplier will make all necessary arrangements to ensure that its generation output does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated in the Generation Interconnection Agreement.

In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

*ENERGY BALANCING SERVICE TARIFF*
Renewable to Retail

## ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's RtR Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

## AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(3) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(4) The LRS must be providing service to RtR Customers.

## APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the OATT, the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities, and is independent of the LRS's forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. The hourly top-up quantity equals the excess in each hour, if positive,

***ENERGY BALANCING SERVICE TARIFF***
Renewable to Retail

of the LRS's aggregate customer load adjusted by the addition of distribution losses over the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected, over its aggregate customer load adjusted by the addition of distribution losses. The locational loss values will be published by the NS Power System Operator. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS's generation portfolio.

**ADMINISTRATION CHARGE**

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $340.97 per month.

**ENERGY CHARGE**

Energy charge for top-up service is made up of the following two components:

***ENERGY BALANCING SERVICE TARIFF***
Renewable to Retail

(1) Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS's forecasted incremental top-up load.

(2) Fixed cost adder reflective of fixed cost energy-related generation costs.

| **Energy Charge Components** | **Cents per kWh** |
|---|---|
| Fuel Cost | 6.275 |
| Fixed Cost Adder | 3.168 |
| Total | 9.443 |

The charge is applicable to top-up energy consumed in each hour.

**ENERGY CREDIT**

6.275 cents per kilowatt hour

The Energy Credit for spill service is set annually and is applicable to spilled energy in each hour.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge will be the administration charge

**SPECIAL CONDITIONS**

(7) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(8) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(9) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage

***ENERGY BALANCING SERVICE TARIFF***
Renewable to Retail

flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(10) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff or the Renewable to Retail Market Transition Tariff.

*STANDBY SERVICE TARIFF*
Renewable to Retail

## STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

> **Capacity adequacy service** – fulfillment of the LRS's obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.
>
> **Top-up capacity service** – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

## AVAILABILITY

This Standby Service Tariff is applicable to the LRS to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and.

(2) The LRS must be providing service to RtR Customers.

## APPLICABILITY

(6) An LRS taking service under this Standby Service Tariff shall also take service under Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff and the Renewable to Retail Market Transition Tariff.

(7) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(8) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

***STANDBY SERVICE TARIFF***
Renewable to Retail

(9) This service is applicable to firm load only.

**ADMINISTRATION CHARGE**

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS's subscribed} * 12}$$

This charge will be $340.97 per month.

**DEMAND CHARGE**

$5.141 per month, per kilowatt (kW) of monthly standby contract demand.

**MINIMUM MONTHLY CHARGE**

The minimum monthly charge will be the administration charge.

**DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND**

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$\text{MSCD} = \text{LWPFD} - min\ (LWPFD,\ (\textstyle\sum_{i=1}^{n}\ CCi * GCi)/(1+PR))$$

Where:

LWPFD is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$\text{LWPFD} = \textstyle\sum_{i=1}^{k}\ (CMPFDi * CMDAF\text{i})$$

"k" is the number of otherwise applicable bundled service rate classes to RtR customers of LRS.

"CMPFDi" is hourly kW Class Monthly Peak Firm Demand of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). The CMPFD for the unmetered

***STANDBY SERVICE TARIFF***
Renewable to Retail

customer class shall be determined by use of research based class load profile data. "CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

| Classes | Jan, Feb, Dec | Mar, Apr | May, June | Jul, Aug, Sep | Oct, Nov |
|---|---|---|---|---|---|
| Domestic | 1.00 | 1.27 | 1.67 | 2.17 | 1.47 |
| Small General | 1.00 | 1.21 | 1.32 | 1.09 | 1.28 |
| General | 1.00 | 1.12 | 1.32 | 1.05 | 1.19 |
| Large General | 1.00 | 1.05 | 1.04 | 0.78 | 0.99 |
| Small Industrial | 1.00 | 1.06 | 1.01 | 0.94 | 1.00 |
| Medium Industrial | 1.00 | 1.14 | 1.08 | 1.01 | 1.02 |
| Large Industrial Firm | 1.00 | 1.10 | 1.03 | 0.89 | 1.09 |
| Unmetered | 1.00 | 8.24 | 7.90 | 7.68 | 2.28 |

"PR" is Planning Reserve (%) (based on Northeast Power Coordinating Council planning criteria, i.e., 20% or as updated)

"CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power.

"GCi" is the generator capacity dedicated to serving LRS load.

"n" is the total number of LRS' generators including those under contract.

**SPECIAL CONDITIONS**

(11) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(12) The LRS's RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

***STANDBY SERVICE TARIFF***
Renewable to Retail

(13) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(14) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Utility and Review Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff or the Renewable to Retail Market Transition Tariff.

***RENEWABLE TO RETAIL MARKET TRANSITION TARIFF***
Renewable to Retail

## PURPOSE

Pursuant to Section 3G(2) of the Electricity Act (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its RtR Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Utility and Review Board (Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

## APPLICABILITY

1) The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff or the Energy Balancing Service Tariff.

2) The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

3) Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

4) The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS's supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

5) An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

***RENEWABLE TO RETAIL MARKET TRANSITION TARIFF***
Renewable to Retail

## ENERGY CHARGE

Energy charge is made up of the following components:

| Energy Charge Components | Cents per kWh |
|---|---|
| Fixed Cost Adder from Energy Balancing Service Tariff | 3.168 |
| 2014 Cost of Service Earnings Adjustment | (0.774) |
| Prior Period Actual Earnings Adjustment | (0.043) |
| Annually Adjusted Energy Savings Credit | 0.000 |
| Annual Energy Cost Adjustment | (0.180) |
| Total | 2.171 |

The Energy Charge is applicable to the LRS's monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

## DEMAND CHARGE

Demand Charge is made up of two components:

| Demand Charge Components | Dollars per kW |
|---|---|
| Demand Charge from Standby Service Tariff | $5.141 |
| Annually Adjusted Demand Savings Credit | $0.000 |
| Total | $5.141 |

The Demand Charge is applicable to the LRS's monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

***RENEWABLE TO RETAIL MARKET TRANSITION TARIFF***
Renewable to Retail

## SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff or the Energy Balancing Service Tariff.

## *DISTRIBUTION TARIFF RATES**

***Note: For certainty, all capitalized terms shall, unless otherwise defined herein, have the meanings ascribed thereto in Distribution Tariff.***

## APPLICABILITY

This schedule provides charges for Distribution System Access applicable to distribution-connected RtR Customers receiving supply of renewable low-impact electricity from a Licenced Retail Supplier as provided for under the Electricity Act (Nova Scotia).

## CHARGES

| **Rate Class** | **Customer Charge** | **Distribution Charge** | **Demand Charge** | **Minimum Monthly Charge** | **Transformer Ownership Credit** |
|---|---|---|---|---|---|
| | **$/month** | **¢/kWh** | **$/kVA** | **$/month** | **$/kVA** |
| Domestic Service | 10.83 | 2.383 | 0.000 | 10.83 | 0 |
| Domestic Service Time of Day | 10.83 | 2.383 | 0.000 | 10.83 | 0 |
| Small General | 12.65 | 2.197 | 0.000 | 12.65 | 0 |
| General (1) | 0 | 0.000 | 5.226 | 12.65 | -0.32 |
| Large General (2) | 0 | 0.000 | 3.224 | 12.65 | -0.32 |
| Small Industrial | 0 | 0.000 | 4.303 | 12.65 | -0.32 |
| Medium Industrial | 0 | 0.000 | 3.347 | 12.65 | -0.32 |
| Large Industrial Firm (2) Rate Code 23 | 0 | 0.000 | 2.327 | 12.65 | -0.32 |
| Outdoor Recreational Light Rate | 0 | 3.400 | 0.000 | 0 | 0 |
| Unmetered Service Rates | 0 | 0.000 | 12.484 | 17.51 | 0 |
| Miscellaneous Small Loads | 0 | 0.000 | 12.484 | 17.51 | 0 |

**Footnotes**

(1) Demand Charges and credits are applicable to kilowatt (kW) demand.
(2) Demand Charges and credits are applicable to kilovolt-ampere of maximum (kVA) demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven months regardless whether service was taken under the bundled or unbundled service.

**MAXIMUM PER KWH CHARGE/MINIMUM BILL**

The same maximum per kWh charges and minimum bills will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above.

**AVAILABILITY**

The same Availability conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.

**SPECIAL CONDITIONS**

The same Special Conditions will apply as stated in tariffs for NS Power Bundled Service for each Rate Class listed above, saving and excepting the Interruptible Rider to the Large Industrial Tariff (Rate Code 25) which will not apply.

(A) **STREET AND AREA LIGHTING**

**RATES**

(1) **INCANDESCENT**

| **Rate Code** | **Watts** | **kWh/Mo.** | **$/Mo.** | **Other** |
|---|---|---|---|---|
| a) | Operating, Maintenance and Capital (Full Charge) | | | |
| 001 | 300 and less | 97 | $10.67 | |
| 002 | Greater than 300 | 154 | 12.92 | |
| b) | Operating Only | | | |
| 003 | 300 and Less | 97 | 3.63 | |

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(2) **MERCURY VAPOUR**

| Rate Code | Watts | kWh/Mo. | $/Mo. | Other |
|---|---|---|---|---|
| a) Operating, Maintenance and Capital (Full Charge) | | | | |
| 100 | 100 | 43 | $9.98 | |
| 101 | 125 | 52 | 11.82 | |
| 102 | 175 | 69 | 10.69 | |
| 103 | 250 | 97 | 12.48 | |
| 104 | 400 | 154 | 14.69 | |
| 105 | 700 | 260 | 19.85 | |
| 106 | 1000 | 363 | 24.74 | |
| 107 | 250 | 212 | 17.63 | Continuous Operation |
| b) Operating and Maintenance Only | | | | |
| 201 | 125 | 52 | $8.81 | |
| 202 | 175 | 69 | 7.72 | |
| 203 | 250 | 97 | 8.79 | |
| 204 | 400 | 154 | 10.92 | |
| 205 | 700 | 260 | 14.90 | |
| 206 | 1000 | 363 | 18.76 | |
| c) Operating Only | | | | |
| 301 | 125 | 52 | $1.94 | |
| 302 | 175 | 69 | 2.56 | |
| 303 | 250 | 97 | 3.63 | |
| 304 | 400 | 154 | 5.76 | |
| 305 | 700 | 260 | 9.74 | |
| 306 | 1000 | 363 | 13.60 | |

(3) **FLUORESCENT**

| **Rate Code** | **Bulb Length** | **Number of Bulbs/Unit** | **kWh/Mo.** | **$/Mo.** | **Other** |
|---|---|---|---|---|---|
| a) Operating, Maintenance and Capital (Full Charge) | | | | | |
| 110 | 24 | 2 | 30 | 13.87 | |
| 111 | 48 | 2 | 85 | 16.18 | |
| 112 | 72 | 2 | 116 | 17.82 | |
| 113 | 72 | 4 | 222 | 22.90 | |
| 114 | 96 | 1 | 47 | 15.03 | |
| 115 | 72 | 1 | 60 | 15.14 | |
| 116 | 48 | 4 | 166 | 19.80 | |
| b) Operating and Maintenance Only | | | | | |
| 213 | 72 | 4 | 222 | $18.60 | |
| 214 | 96 | 1 | 47 | 12.06 | |
| 215 | 72 | 1 | 60 | 12.56 | |
| 216 | 48 | 4 | 166 | 16.55 | |
| 217 | 48 | 1 | 49 | 12.13 | |
| 218 | 48 | 2 | 85 | 13.49 | |
| c) Operating Only | | | | | |
| 330 | 35 | 4 | 47 | 1.75 | |

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only

| | | | | |
|---|---|---|---|---|
| 117 | 72 | 4 | 486 | $8.30 |
| 118 | 24 | 2 | 66 | 1.12 |
| 119 | 48 | 4 | 364 | 6.24 |
| 120 | 96 | 2 | 254 | 4.35 |
| 150 | 96 | 4 | 613 | 10.48 |

b) Photocell Operation - Operating Only

| | | | | |
|---|---|---|---|---|
| 310 | 24 | 2 | 30 | $1.13 |
| 311 | 48 | 4 | 166 | 6.24 |

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| | | | | |
|---|---|---|---|---|
| 312 | 72 | 2 | 116 | 4.36 |
| 313 | 72 | 4 | 222 | 8.29 |
| 314 | 96 | 1 | 47 | 1.75 |
| 315 | 72 | 1 | 60 | 2.25 |
| 350 | 96 | 4 | 280 | 10.50 |

(5) **LOW PRESSURE SODIUM**

| **Rate Code** | **Watts** | **kWh/Mo.** | **$/Mo.** | **Other** |
|---|---|---|---|---|
| a) Operating, Maintenance and Capital (Full Charge) | | | | |
| 130 | 135 | 60 | $23.51 | |
| 131 | 180 | 80 | 26.85 | |
| 132 | 90 | 45 | 22.94 | |
| b) Operating and Maintenance Only | | | | |
| 231 | 180 | 80 | 18.47 | |
| c) Operating Only | | | | |
| 331 | 180 | 80 | 3.00 | |

(6) **HIGH PRESSURE SODIUM**

a) Operating, Maintenance and Capital (Full Charge)

| | | | | |
|---|---|---|---|---|
| 121 | 250 | 100 | $12.12 | |
| 122 | 400 | 150 | 14.11 | |
| 123 | 70 | 32 | 9.37 | |
| 124 | 100 | 45 | 9.88 | |
| 125 | 150 | 65 | 10.81 | |
| 126 | 100 | 99 | 15.03 | Continuous Operation |

(6) **HIGH PRESSURE SODIUM (**cont'd)

| Rate Code | Watts | kWh/Mo. | $/Mo. | Other |
|---|---|---|---|---|
| b) Operating and Maintenance Only | | | | |
| 221 | 250 | 100 | $8.91 | |
| 222 | 70 | 32 | 6.35 | |
| 223 | 100 | 45 | 6.84 | |
| 224 | 150 | 65 | 7.59 | |
| c) Operating Only | | | | |
| 321 | 250 | 100 | $3.75 | |
| 322 | 70 | 32 | 1.19 | |
| 323 | 100 | 45 | 1.68 | |
| 324 | 150 | 65 | 2.43 | |
| 326 | 400 | 150 | 5.62 | |
| 327 | 500 | 183 | 6.86 | |
| 328 | 1000 | 363 | 13.61 | |
| 329 | 1500 | 500 | 18.73 | |

(7) **METALLIC ADDITIVE**

| | | | |
|---|---|---|---|
| a) Operating, Maintenance and Capital (Full Charge) | | | |
| 140 | 400 | 150 | $17.68 |
| 141 | 1000 | 360 | 31.42 |
| 142 | 250 | 100 | 19.87 |
| 143 | 150 | 67 | 18.62 |
| 144 | 100 | 50 | 17.99 |
| b) Operating Only | | | |
| 341 | 1000 | 360 | $13.48 |
| 342 | 400 | 150 | 5.62 |
| 343 | 250 | 100 | 3.75 |
| 344 | 175 | 75 | 2.81 |
| 345 | 150 | 67 | 2.50 |
| 346 | 100 | 50 | 1.87 |

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

| Rate Code | $/Mo. | Other |
|---|---|---|
| 530 | $0.06 | Non – Continuous |
| 531 | $0.09 | Continuous |

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

| Rate Code | Watts | kWh/Mo. | $/Mo. |
|---|---|---|---|
| 532 | 44 | 15 | $0.56 |
| 533 | 66 | 22 | 0.82 |
| 534 | 88 | 29 | 1.09 |
| 535 | 92 | 31 | 1.16 |
| 536 | 105 | 35 | 1.31 |
| 537 | 170 | 57 | 2.13 |
| 539 | 110 | 37 | 1.39 |
| 540 | 65 | 22 | 0.82 |
| 541 | 55 | 18 | 0.67 |
| 542 | 83 | 28 | 1.05 |
| 543 | 48 | 16 | 0.60 |
| 544 | 72 | 24 | 0.90 |

(10) **LIGHT EMITTING DIODE (LED) – Operating & Capital Only***

| Rate Code | Watts | kWh/Mo. | $/Mo. | Other |
|---|---|---|---|---|
| 615 | 44 | 15 | $7.74 | |
| 616 | 55 | 18 | 7.85 | |
| 623 | 28 | 9 | 7.52 | |
| 624 | 50 | 17 | 7.82 | |
| 625 | 72 | 24 | 8.08 | |
| 626 | 100 | 33 | 8.42 | |
| 627 | 200 | 67 | 9.69 | |

* While fixture maintenance costs associated with LED streetlights may occur, this component is currently not reflected in the rates.

(11) **LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)**

| **Rate Code** | **Watts** | **kWh/Mo.** | **$/Mo.** | **Other** |
|---|---|---|---|---|
| 724 | 55 | 18 | $7.78 | |
| 740 | 190 | 63 | 15.83 | |
| 741 | 261 | 87 | 18.46 | |
| 742 | 124 | 41 | 12.15 | |
| 743 | 84 | 28 | 10.98 | |

The Extra Large Industrial Active Demand Control Tariff (ELIADC) provides a mechanism whereby Port Hawkesbury Paper LP (PHP, the Mill, the Customer) pays the forecast incremental costs of its annual forecast service expressed as a levelized Customer Baseline Load (CBL) plus makes a contribution to utility costs, while providing Nova Scotia Power (NS Power) with control of PHP's load such that NS Power's overall system costs can be reduced and system reliability can be improved for the benefit of all NS Power customers.

## AVAILABILITY

(a) This Tariff is applicable to operations at PHP's mill site at Point Tupper, and is premised upon PHP's electricity requirements being exclusively served by NS Power.

(b) In addition to the priority interruptible service load reduction requirements prescribed in this Tariff, PHP's load shall be further managed by NS Power in accordance with the Active Demand Control – Energy Supply Protocols attached as Schedule 1 to this Tariff.

(c) The service voltage shall not be less than 138 kV, line to line, at each delivery point. Service is provided at the supply side of the Mill's transformation equipment. PHP must own the transformation facilities and no transformer ownership credit is applicable.

(d) This Tariff cannot be taken in conjunction with other tariffs unless approved by the Nova Scotia Utility and Review Board (Board).

## COST OF ELECTRICITY UNDER THE ELIADC TARIFF

The price paid by PHP for electricity under this Tariff will be based on the forecast incremental cost to serve PHP at an assumed levelized baseline load level, plus an adder to contribute to the reduction of the cost of service to other NS Power customers, less a credit to recognize system savings enabled by PHP's granting Active Demand Control of its load to NS Power. The credit is also intended to incent PHP to assist NS Power in realizing the full potential value of Active Demand Control by allowing PHP to share in the resulting system savings.

The pricing elements comprising the ELIADC are:

- Customer Baseline Energy Charge (CBL Energy Charge)
- Customer Baseline Adder (CBLA)
- Variable Capital Charge
- Active Demand Control Credit

### *Minimum Payment*

The ELIADC Tariff requires that a minimum payment shall be made by PHP in respect of each tariff year, which shall not be less than the sum of:

(a) NS Power's actual total incremental cost of serving PHP during the year (including the cost of fuel and purchased power, line losses, variable operating costs and variable capital costs for NS Power's incremental generation and delivery of electricity to the customer), plus
(b) $4.00 multiplied by the total number of MWh supplied in the year.

Any adjustments required to achieve this minimum payment amount will be determined and charged to PHP after year end.

***Customer Baseline Energy Charge and Contribution to Utility Costs***

In advance of each tariff year, PHP shall advise NS Power of its forecast annual and monthly energy requirements for the subsequent calendar year, including the anticipated dates and durations of PHP's major scheduled maintenance periods. Upon receipt of such forecast, NS Power will then calculate, in $/MWh, its forecast annual cost to serve PHP at a levelized baseline load level (i.e., the Customer's average demand will be assumed to be the same in each hour after taking into account major scheduled maintenance) to produce the CBL Energy Charge.

The CBL Energy Charge calculation will be inclusive of all incremental, non-capital costs to serve PHP and will assume no economic load shifting (e.g. no reductions in usage in high-cost hours or increased usage in low-cost hours). The CBL Energy Charge will include the forecast cost of fuel and purchased power, line losses, and variable operating costs for NS Power's incremental generation and delivery of electricity to PHP. The CBL Energy Charge will form the basis of the ELIADC Energy Charge for the upcoming calendar year.

A CBL Adder (CBLA) will be calculated with reference to the forecast CBL Energy Charge. As the forecast CBL Energy Charge ($/MWh) decreases, the CBLA increases.

- When the forecast CBL Energy Charge is under $61.75/MWh, the CBLA is calculated as 75 percent of the difference between the forecast CBL and $61.75/MWh, plus $1/MWh.
- When the forecast CBL Energy Charge is at or over $61.75/MWh, the difference between the forecast CBL Energy Charge and $61.75/MWh is assigned a value of zero and the CBLA is calculated as $1/MWh.

The CBL Energy Charge and the associated CBLA shall be submitted for Nova Scotia Utility and Review Board (Board) approval on an annual basis as part of the annual proceeding by which NS Power's Annually Adjusted Rates are established.

In addition to the CBL Energy Charge and CBLA, PHP will pay a Variable Capital Charge (VCC) for NS Power's incremental generation and delivery of electricity to PHP in the amount of $**1.13**/MWh.

In summary, the Tariff energy charge per MWh will be calculated as follows:

$$ELIADC\ Energy\ Charge = CBL\ Energy\ Charge + CBLA + VCC$$

**INTRA-YEAR MODIFICATIONS TO THE CBL ENERGY CHARGE**

NS Power will utilize its established forecasting methodology to determine the CBL Energy Charge. PHP will undertake commercially reasonable efforts to accurately forecast its energy usage.

If, during any year, certain circumstances, such as those described in the next paragraphs, change significantly resulting in a material impact on the appropriate CBL Energy Charge to be paid by PHP during the year, NS Power may, upon approval of the Board, revise the CBL Energy Charge on a prospective basis.

In recognition that the calculation of the CBL Energy Charge for 2020 may be materially impacted if there are delays to the start date of deliveries of the NS Block energy import beyond June 1, 2020, if NS Power determines that any such delay will have a material impact on the appropriate CBL Energy Charge to be paid by PHP for 2020, then the CBL Energy Charge will be subject to recalculation pursuant to this provision.

Additional circumstances which, if changed significantly, would warrant reassessment of the CBL Energy Charge could include, but are not limited to:

(a) It becomes apparent that the CBL Energy Charge plus the CBLA plus the Variable Capital Charge will not result in the recovery of the actual incremental cost to serve plus $4/MWh;

(b) Material and unexpected change in the cost of generation as compared to the CBL Energy Charge calculation;

(c) Material and unexpected increased electricity consumption by PHP during the year, such as significant physical plant modification (as signified by a specific capital expenditure beyond normal annual capital spending), a change in product line or a material non-forecast change in product demand; and

(d) Material and unexpected decrease in electricity consumption by PHP during the year (such as due to plant shutdowns, labour issues, or market downtime).

If PHP and NS Power are unable to agree on the required changes to the CBL Energy Charge as a result of any of the above modifications, the matter may be submitted to the Board by either party on an expedited basis for adjudication. Revisions to the CBL Energy Charge will not change the Minimum Payment to be made by PHP.

## ACTIVE DEMAND CONTROL AND SCHEDULE VARIANCE

NS Power shall be entitled to actively manage PHP's load in accordance with the terms and conditions set out in the Active Demand Control – Energy Supply Protocol attached as Schedule 1 to this Tariff.

Annually, NS Power shall report to the Board to confirm the dollar value of system savings that have been achieved through Active Demand Control of PHP's load under the Protocol, taking account of the impacts of any variances by PHP from the dispatch schedules issued to it by NS Power and any adjustments arising from schedule variances if required. NS Power shall endeavor to submit this report no later than 60 days after the end of a tariff year.

PHP will be entitled to a credit equal to 25 percent of the cost differential between the CBL Energy Charge and the actual annual cost to serve PHP during the given tariff year. Such payments to the Customer will be made via an annual lump sum payment.

## TERM

The initial term of this Tariff is 2020-2023 inclusive, unless revised per a Decision of the Nova Scotia Utility and Review Board (Term). Prior to the end of the initial term, NS Power or PHP may apply to the Board for approval of a subsequent term for this Tariff, including the approval of the pricing elements of the Tariff to be applied during the subsequent term.

## REOPENER

If, at any time during the Term, NS Power or PHP determines that the ELIADC Tariff is not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the Tariff, or the components thereof, on a prospective basis. If necessary, and to protect customers, the Board may grant such approval on an expedited basis. Following any adjustment, PHP would be provided the opportunity to determine whether to remain on the Tariff.

## DSM COST RECOVERY RIDER

The Demand Side Management Cost Recovery Charge is not applicable to PHP, and PHP will have no standing to participate in DSM-related proceedings.

## FUEL ADJUSTMENT MECHANISM (FAM)

No FAM charges or credits shall be applicable to PHP, and PHP will have no standing to participate in FAM-related processes or proceedings unless it is proposed that a FAM-related charge be assessed against PHP or unless any such process or proceeding specifically deals with an issue that can directly impact on NS Power's incremental electricity costs.

## MINIMUM LOAD REQUIREMENT

NS Power will withdraw the availability of this tariff, if, on a consistent basis, PHP is not maintaining a regular demand of 25,000 kVA.

## INTERRUPTIBILITY

The Mill will reduce its load by, at a minimum, the amount requested by NS Power within 10 minutes of such request by NS Power. Following such interruption, service may only be restored by the Mill with the approval of NS Power.

PHP will make available suitable contact telephone numbers of a person or persons who are able to interrupt the required load within ten minutes.

Load interruption calls will be made to PHP in advance of all such calls to NS Power's Large Industrial Interruptible Rider customers. Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by NS Power, NS Power may hold this load as Operating Reserve as required by system conditions. When interruptions are required, NS Power will exercise the automated control of the customer's load to interrupt the customer load.

PHP is expected to comply with all calls for interruption. Failure to comply in whole or in part with a request to interrupt load will result in penalty charges, payable within 15 business days unless such penalty payment is being contested in good faith. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge will be equal to the amount of the applicable formula cost for energy taken under this Tariff effective at that time for the consumption used in the month.

The Performance Penalty which is based on PHP's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual demand (above that required by the interruption request) remaining in the third interval directly following two complete 5-minute intervals after the interruption call was delivered by telephone call.

"B" is PHP's average demand in excess of the compliance level based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A".

The total penalty will not exceed two times the cost of the formula amount, effective at that time for the consumption used in that month.

Should PHP fail to respond during subsequent calls within the same month, the same penalties will apply for each failure to interrupt.

Interruptions will be limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours per year.

***Conversion of Interruptible Load to Firm***

Should PHP desire to be served under any applicable firm service tariff, a five-year advance written notice must be given to NS Power so as to ensure adequate capacity availability. Requests for a conversion to firm service will be treated in the same manner as all other requests for firm service received by NS Power. NS Power may, however, permit an earlier conversion. If PHP desires to return to interruptible service in the future, PHP may convert to an interruptible service tariff following two years of service under the firm tariff schedule. NS Power may permit an earlier conversion from firm to interruptible service.

Order of Interruptibility

In the event an interruption call is required in order to avoid shortfalls in system electricity supply, interruptible load will be called upon to provide capacity to NS Power in the following order:

1. Generation Replacement and Load Following (GRLF) Tariff;
2. Extra Large Industrial Active Demand Control Tariff;
3. Shore Power Tariff;
4. Interruptible Rider to the Large Industrial Tariff.

In situations in which load of the customer under this Tariff is held as Operating Reserve, NS Power may change the above order of interruption by interrupting Large Industrial Interruptible Rider Tariff customers whose load is not held as Operating Reserve before interrupting the Customer.

**MAINTAIN SYSTEM INTEGRITY**

PHP will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a separate operating agreement.

In assessing issues that might unduly affect the integrity of the power supply system, the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

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## SECURITY FOR PAYMENTS

NS Power shall invoice PHP weekly, and PHP shall pay the billed amount net 7 days. As security for payment, PHP shall provide NS Power a letter of credit from time to time. The form, amount, and issuer of the letter of credit will be satisfactory to NS Power. To the extent that a letter of credit introduces a lag time and there are additional costs to NS Power, these will be paid by PHP not NS Power or its customers.

## SEPARATE SERVICE AGREEMENT

NS Power reserves the right to have a separate service agreement if, in the opinion of NS Power, issues not specifically set out herein must be addressed for the ongoing benefit of NS Power and its customers.

## POWER FACTOR CORRECTION

Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total Mill load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the CBL Energy Charge:

| Power Factor | Constant | Power Factor | Constant |
|---|---|---|---|
| 90-100% | 1.0000 | 65-70% | 1.1255 |
| 80-90% | 1.0230 | 60-65% | 1.1785 |
| 75-80% | 1.0500 | 55-60% | 1.2455 |
| 70-75% | 1.0835 | 50-55% | 1.3335 |

## METERING COSTS

Metering will normally be at the low voltage side of the transformer and, for measurement and, where applicable, billing purposes, meter readings will be increased by 1.75%. Should the Mill's requirements make it necessary for NS Power to provide primary metering, PHP will be required to make a capital contribution equal to the additional cost of primary metering as opposed to the cost of secondary metering. The costs of any special metering or communication systems required by PHP in connection with service under this Tariff shall be paid for by PHP as a capital contribution.

**EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF**

**Schedule 1: Active Demand Control Energy Supply Protocol** 

**Part A – Definitions**

**ADC:** Active Demand Control.

**ADC Operating Procedure:** Procedure document maintained by Nova Scotia Power System Operator (NSPSO) that describes the operation and usage of ADC for the NSPSO for Current Hour, Operating Hour 1 & Operating Hour 2.

**CBL:** Customer Baseline Load.

**CBL & ADC Benefit Calculation:** Process maintained by Nova Scotia Power (NS Power) to calculate the CBL Energy Charge, forecasted ADC benefit and actual ADC benefit.

**Current Hour:** The current hour of operation, which is only dispatchable by NSPSO.

**Dispatchable Hours:** All hours beyond Hour 2, as described (hour 3, 4 and beyond) in Section 4.3.10 of the NS Market Rules that are open for redispatch by NS Power.

**Excess Energy:** Generation which is in excess of the needs of the electric system and which cannot be stored.

**Force Majeure**: Any event or circumstance or combination of events or circumstances (including major equipment failure) that materially and adversely affects either party in the performance of its obligations in accordance with the terms of this Protocol, but only if and to the extent such events and circumstances are not within the affected party's reasonable control, and which the party claiming Force Majeure could not have prevented through reasonable skill and care.

**Hour 1:** The next hour, as described (hour 1) in Section 4.3.10 of the NS Market Rules. Dispatchable by NSPSO, and NS Power by exception only.

**Hour 2:** The next hour +1, as described (hour 2) in Section 4.3.10 of the NS Market Rules. Dispatchable by NSPSO, and NS Power by exception only.

**Intra-Day Demand Schedule (ADC Schedule 4):** An hourly demand profile that includes all Dispatchable Hours for a consecutive 24-hour duration. This will be provided by NS Power as a forecast to Port Hawkesbury Paper LP (PHP) and NSPSO for the upcoming period. NSPSO will confirm the schedule and only change dispatch if required for a change in system conditions.

**Monthly Demand Schedule (ADC Schedule 1):** A monthly, indicative, demand profile that includes a maximum and minimum demand profile for all months of the year, or all remaining months of the year if a system rerun is required. These forecasts will be performed annually and

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updated as required by NS Power. Refer to Part B. The results of these runs will be presented and shared with PHP as ADC Schedule 1.

**NS Market Rules:** Nova Scotia Wholesale and Renewable to Retail Electricity Market Rules.

**NS OATT:** Nova Scotia Power Incorporated Open Access Transmission Tariff including the Standards of Conduct (Attachment E).

**NS Power:** Nova Scotia Power Groups – Fuels, Energy and Risk Management (FERM), Portfolio Optimization, Customer Solutions and any other non-System Operator Nova Scotia Power function.

**NSPSO:** Any Nova Scotia Power System Operator function.

**Operating Mode Characteristics Schedule:** The schedule referenced in Part D of this Protocol.

**PHP:** Port Hawkesbury Paper LP.

**Seven Day Demand Schedule (ADC Schedule 3):** An hourly demand profile produced and co-optimized as part of the system by NS Power each business day. The Seven Day Demand Schedule includes all Dispatchable Hours, starting 00:00 for the upcoming business day, for a 168-hour duration.

**Tariff:** The Extra Large Industrial Active Demand Control Tariff.

**Weekly Demand Schedule (ADC Schedule 2):** An annual, indicative, demand profile that includes a maximum and minimum demand profile for each week of the year or all remaining weeks of the year, if a system rerun is required. This will inform the development of the Seven Day Demand Schedule. These forecasts will be performed annually and updated as required by NS Power.

**Part B – Protocol Forecasting and Operation**

1. Annually, no later than the seventh business day of November, NS Power will forecast the Monthly Demand Schedule, Weekly Demand Schedule, and monthly and weekly limits based on PHP's demand forecast for the upcoming year (January 1 to December 31). The results of these forecasts will be published to PHP and NSPSO in ADC Schedules 1 & 2. As and when required during the year, NS Power will reforecast the Monthly Demand Schedule and Weekly Demand Schedule and update ADC Schedules 1 & 2. The values in ADC Schedules 1 & 2 will bound the daily forecast runs used to create the Seven Day and Intra Day Demand Schedules.

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2. On a daily basis (non-statutory holiday weekdays), NS Power will provide PHP and NSPSO with a Seven Day Demand Schedule that is optimized as part of the NS Power system day-ahead planning process. PHP's demand will be co-optimized as part of the full NS Power portfolio. As part of this co-optimization:

   (a) With respect to forecast PHP annual capital shutdowns, PHP will provide a minimum of one month's advance notice of the timing and duration of the shutdowns; and
   (b) With respect to forecast PHP regular maintenance shutdowns, PHP will provide a minimum of seven days advance notice of the timing and duration of the shutdowns.

3. From time to time, a request may be made to PHP to adjust their daily demand from the Seven Day Demand Schedule in anticipation of significant events. An example of this would be a weather event that is forecasted. Such requests must fall within the agreed Operating Mode Characteristics Schedule and the ADC Operating Procedure.

4. Intra-Day, no later than the start of Hour 1, NS Power will provide PHP and NSPSO with an updated Intra-Day Demand Schedule when a dispatch change is required. This request will supersede the previously submitted requests.

5. If, during the Current Hour, Hour 1 and/or Hour 2, system conditions change unexpectedly such that they have a material impact (positive or negative) on system costs, NSPSO will contact PHP with a schedule change (an increase or reduction in demand) provided such changes fall within: the agreed Operating Mode Characteristics Schedule, the final communicated PHP shutdowns, and the ADC Operating Procedure. Otherwise the most recent schedule submitted by NS Power will be set as the hourly demand. This will represent the final demand schedule with any deviations tracked as a schedule variance.

6. As noted in the Tariff, if, during the current year, NS Power determines that there are significant adverse differences between the CBL Energy Charge (as defined in the Tariff) and the incremental costs of service, NS Power, with approval of the NSUARB, can adjust the rate on a prospective basis as provided for in the Tariff. In such circumstances, NS Power shall also update and communicate its expected forecast of ADC benefit for the remainder of the year.

7. NS Power, NSPSO and PHP will exchange the following information on a confidential basis through the methods described below:

   7.1. Intra-Day Demand Schedule (ADC Schedule 4) – NS Power;
   7.2. Seven Day Demand Schedule (ADC Schedule 3) – NS Power;
   7.3. Weekly Demand Schedule (ADC Schedule 2) – NS Power;

7.4. Monthly Demand Schedule (ADC Schedule 1) – NS Power;
7.5. Nova Scotia's Base load forecast – NSPSO;
7.6. Nova Scotia's aggregate wind forecast – NSPSO;
7.7. PHP pulp storage levels – PHP; and
7.8. PHP discrete line operation (i.e. what lines are in and out of service in a period) – PHP.

NS Power and PHP agree that, in order to (1) assist PHP to efficiently respond to any dispatch schedule changes that may be requested by NS Power and/or NSPSO in a manner that benefits the NS Power electric system, and (2) enhance collaboration between the parties when responding to unplanned system changes, NS Power will provide PHP with access to certain system information. On an automated basis, NS Power will provide PHP with information in respect of its system demand and the aggregation of generation types (specifically coal, gas, oil, combustion turbines, imports and hydro) as a snapshot of the current system condition. PHP agrees that such information is to be used exclusively for the foregoing purposes. During any period in which this data is unavailable due to technical issues, PHP will refer to the https://www.nspower.ca/en/home/about-us/todayspower.asp until NS Power is able to re-establish the provision of this data on a timeline that is reasonable, given NS Power's other business priorities. Any use of the data for purposes beyond operational preparedness can result in the suspension of the data sharing.

8. On an annual basis, NS Power will calculate the actual ADC benefit consistent with the CBL & ADC Benefit Calculation.

**Part C – Conditions**

9. Subject only to reasons of health, safety, environmental, system reliability, and Force Majeure events, PHP must not deviate from the NS Power/NSPSO final demand schedule. NS Power/NSPSO must comply with the weekly demand requirements as determined by the Weekly Demand Schedule. In the situation where the Weekly Demand Schedule requirements are not complied with, NSP/NSPSO will work collaboratively with PHP to address the discrepancy.

10. Following any health, safety, environmental, system reliability, or Force Majeure event, PHP and NS Power will use commercially reasonable efforts to restore their applicable operation to normal as soon as possible and without undue delay. In such circumstances, PHP will advise NS Power as soon as possible of any change in availability of PHP's operating modes to allow NS Power to adjust its dispatch schedules accordingly. PHP and NS Power will maintain, as a minimum, hourly contact with each other in the hours following Force Majeure events to keep each other aware of the other's status.

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11. In the case of NS Power or PHP's inability to follow the dispatch plan that triggers one of the circumstances as set out in Appendix 1, the timing, magnitude, and reason for the deviation will be tracked and noted by NS Power/NSPSO. This Appendix may be updated by agreement between NS Power and PHP if other circumstances arise that require variances from the scheduled dispatch to be tracked. Updates to this Appendix will be filed with the NSUARB.

12. Subject to available generation or load, as the case may be, efforts will be made to reconcile variances in a timely manner, including by NS Power and PHP mutually agreeing to deviate from the previously agreed Operating Mode Characteristics Schedule, with the goal of achieving similar system costs and service to the Mill as would have been achieved if the original dispatch had been followed.

13. The overall impact on system costs (if any) for the tracked deviations will be initially estimated on a quarterly basis, and assessed at the end of the year by NS Power. If a cost is determined, the ADC credit payment to PHP will be adjusted accordingly.

14. PHP, NS Power and NSPSO shall maintain a scheduling and/or operations team available to each other on a continuous 24 hour, 7 days a week basis.

15. PHP's scheduling and operations team shall be empowered with the authority to acknowledge and adjust PHP's demand on behalf of PHP for the supplied Demand Schedule.

16. This Protocol does not supersede any requirement or obligation as defined in both the NS OATT (including the Standards of Conduct) and NS Market Rules. If a change to either NS OATT and/or NS Market Rules occurs, this Protocol will be updated to reflect any changes, if applicable.

17. For the purposes of planning, PHP will provide NS Power and NSPSO with its expected annual capital outage timing. This data will be provided in a timely manner, to be included in the NS Power/NSPSO annual planning process. The parties will work collaboratively to co-optimize the timing of PHP outages to provide the best fit for the system while respecting PHP's limitations and requirements consistent with Part B, section 2.

18. All energy dispatch decisions as they relate to system demand will be performed at the sole discretion of NS Power and/or NSPSO. This includes, but is not limited to, generation dispatch levels, unit commitments, outage planning and/or import/export energy.

19. The dispatch of PHP demand level will be performed by NS Power and/or NSPSO and must fall within the agreed Operating Mode Characteristics Schedule and the ADC Operating Procedure.

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## Part D – Operating Mode Characteristics Schedule

For the purpose of planning, dispatch and forecasting, PHP's loading levels will be separated into 9 distinctive operating modes. Only one mode will be able to operate at any given time.

The Operating Mode Characteristics Schedule will include (i) maximum and minimum, up and down time of each operating level, (ii) mill ramp rates, (iii) mill outages planning, (iv) pulp storage levels, and (v) individual line operating modes. This Schedule will be used in the preparation of the demand schedules, the calculation of the CBL incremental cost and the overall ADC benefit achieved as a result of the dispatch of PHP's load. NS Power and NSPSO will be required to dispatch PHP's load consistent with the Operating Mode Characteristics Schedule, including the maximum and minimum limits in ADC Schedules 1 & 2.

This schedule will also contain the maximum and minimum amounts of Annual, Monthly and Weekly energy requirements.

The Operating Mode Characteristics Schedule will be initially developed by PHP in consultation with NS Power and can be changed from time to time by agreement of PHP and NS Power.

## Appendix 1

### Circumstances in which Variances from Scheduled Dispatch Will Be Tracked

The variance from the scheduled dispatch results in:

- A change in NS Power unit commitment(s)
- A need for NS Power to rebalance a fuel position
- The redispatching of generation from Wreck Cove
- A reduction in the value of an NS Power export or import opportunity
- A condition of Excess Energy
- NS Power/NSPSO is forced to dispatch PHP outside the Operating Mode Characteristics Schedule

## SCHEDULE 1: SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

This service is required to schedule the movement of power through, out of, within, or into an Operating Area. This service can be provided only by the operator of the Operating Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Operating Area operator. The charges, payable monthly, for Scheduling, System Control and Dispatch Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Point-to-Point Transmission Service:</u>

| **Point-to-Point Transmission Service** | |
|---|---|
| **Delivery Period** | **Charge($)** |
| Yearly | One twelfth of $4,997.38/MW of Reserved Capacity per year |
| Monthly | $416.45/MW of Reserved Capacity per month |
| Weekly | $96.10/MW of Reserved Capacity per week |
| On-Peak Daily | $19.22/MW of Reserved Capacity per day |
| Off-Peak Daily | $13.69/MW of Reserved Capacity per day |
| On-Peak Hourly | $1.20/MW of Reserved Capacity per hour |
| Off-Peak Hourly | $0.57/MW of Reserved Capacity per hour |

On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

Network Integration Transmission Service:

$353.98/MW of Network Integration Transmission Service per month.

## SCHEDULE 2: REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities (in the Operating Area where the Transmission Provider's transmission facilities are located) under the control of the operating area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Operating Area operator) or indirectly by the Transmission Provider making arrangements with the Operating Area operator that performs this service for the Transmission Provider's Transmission system. The Transmission Customer must purchase this service from the transmission Provider or the Operating Area operator. The charges, payable monthly, for such service are based on the rates set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Operating Area operator.

Point-to-Point Transmission Service:

| **Point-to-Point Transmission Service** | |
|---|---|
| **Delivery Period** | **Charge($)** |
| Yearly | One twelfth of $2,579.68/MW of Reserved Capacity per year |
| Monthly | $214.97/MW of Reserved Capacity per month |
| Weekly | $49.61/MW of Reserved Capacity per week |
| On-Peak Daily | $9.92/MW of Reserved Capacity per day |
| Off-Peak Daily | $7.07/MW of Reserved Capacity per day |
| On-Peak Hourly | $0.62/MW of Reserved Capacity per hour |
| Off-Peak Hourly | $0.29/MW of Reserved Capacity per hour |

(On-Peak days for this service are defined as Monday to Friday. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.)

Network Integration Transmission Service:

$182.76/MW of Network Integration Transmission Service per month.

## SCHEDULE 3: REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Operating Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The charges, payable monthly, for Regulation and Frequency Response Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Regulation (Point-to-Point Transmission Service):</u>

The minimum period for which this service is available from the Transmission Provider is one day.

| **Regulation (Point-to-Point Transmission Service)** | |
|---|---|
| **Delivery Period** | **Charge($)** |
| Yearly | One twelfth of $2,604.69/MW of Reserved Capacity per year |
| Monthly | $217.06/MW of Reserved Capacity per month |
| Weekly | $50.09/MW of Reserved Capacity per week |
| Daily | $7.14/MW of Reserved Capacity per day |

Regulation (Network Integration Transmission Service):

$217.06/MW of Network Integration Transmission Service per month.

Load Following (Point-to-Point Transmission Service):

The minimum period for which this service is available from the Transmission Provider is one day.

| **Load Following (Point-to-Point Transmission Service)** | |
|---|---|
| **Delivery Period** | **Charge($)** |
| Yearly | One twelfth of $9,322.16/MW of Reserved Capacity per year |
| Monthly | $776.85/MW of Reserved Capacity per month |
| Weekly | $179.27/MW of Reserved Capacity per week |
| Daily | $25.54/MW of Reserved Capacity per day |

Load Following (Network Integration Transmission Service):

$776.85/MW of Network Integration Transmission Service per month.

Customer Obligations for Self-Supply and Third-Party Supply:

The customer obligation for self-supply or third-party supply of Regulation is equal to 3.5 percent of Reserved Capacity for Point-to-Point Transmission Service and 3.5 percent of the Network Load for Network Integration Transmission Service.

The customer obligation for self-supply or third-party supply of Load Following is equal to 9.1 percent of Reserved Capacity for Point-to-Point Transmission Service and 9.1 percent of Network Load for Network Integration Transmission Service.

## SCHEDULE 4: ENERGY IMBALANCE SERVICE

This Schedule 4 is not applicable to Licenced Retail Suppliers.

The Generation Forecasting Service set out in Schedule 4A of the OATT will apply to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within an Operating Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation. To the extent the Operating Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

For a bilateral schedule of a single load and its single generator, this ancillary service will be applied to the net of the generation and load imbalance. Otherwise, this Ancillary Service will be applied separately to deviations from load schedules and deviations from generation schedules. This ancillary service does not apply to power exported from the Operating Area, which is covered by the Generation Balancing Service of the Standard Generator Interconnection and Operation Agreement.

Energy Imbalance Service does not apply to inadvertent energy imbalances that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to

- Respond to transmission, generation or load contingencies.

For the purposes of Energy Imbalance Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Load Energy Imbalance Associated with Point-to-Point or Network Integration Transmission Service:

For each Transmission Customer taking service under Part II or Part III of this Tariff, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

A deviation band of +/- 1.5 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be applied hourly to any net load energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s).

Parties should attempt to eliminate energy imbalances within the limits of the deviation band within the billing month in accordance to the following:

- For hourly imbalances that arise during peak hours, such imbalances should be eliminated via deliveries or withdrawals during peak hours; and

- For hourly imbalances that arise during non-peak hours, such imbalances should be eliminated via deliveries or withdrawals during non-peak hours.

Net load energy imbalances within the deviation band that have not been eliminated at the end of the billing month will be subject to the charges set below:

- Energy supplied by the Transmission Provider during peak hours to compensate for a net shortfall in peak hours delivery over the billing month will be charged at the average on-peak system marginal cost for the billing month. Energy supplied by the Transmission

Provider during non-peak hours to compensate for a net shortfall in non-peak hours delivery over the billing month will be charged at the average non-peak system marginal cost for the billing month.

- Energy supplied to the Transmission Provider during peak hours as a net excess of the peak hours delivery over the billing month will be purchased by the Transmission Provider at the average on-peak system marginal cost for the billing month. Energy supplied to the Transmission Provider during non-peak hours as a net excess of the non-peak hours delivery over the billing month will be purchased by the Transmission Provider at the average non-peak system marginal cost for the billing month.

Energy imbalances outside of the deviation band are not eligible for elimination and are subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net hourly shortfall in delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

<u>Generation Energy Imbalance - Dispatchable Generators:</u>

For Dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

Generation Energy Imbalance - Non-Dispatchable Generators

For Non-dispatchable Generators in the Transmission Provider's Operating Area supplying load in the Transmission Provider's Operating Area, Energy Imbalance Service will be provided by the Transmission Provider under the following terms and conditions:

Energy Imbalances inside a deviation band of +/- 10 percent of the scheduled transaction (with a minimum deviation band of +/- 2 MW) will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at the hourly system marginal cost in the hour of the deviation.

All deviations from schedule outside of the +/- 10 percent deviation band will be subject to charges as set forth below:

- Energy supplied by the Transmission Provider to compensate for a net shortfall in the hourly delivery will be charged at 110 percent of the hourly system marginal cost in the hour of the deviation.

- Energy supplied to the Transmission Provider in net excess of the hourly delivery will be purchased by the Transmission Provider at 90 percent of the hourly system marginal cost in the hour of the deviation.

## SCHEDULE 4A: GENERATION FORECASTING SERVICE

This Generation Forecasting Service set out in Schedule 4A of the OATT applies to Licenced Retail Suppliers only and is not applicable to any other Eligible Customer. Generation Forecasting Service addresses the accuracy of generation scheduling by Licenced Retail Suppliers.

This Schedule does not apply to forecasting discrepancies that occur as a result of actions directed by the Operating Area operator to:

- Balance total load and generation for the Operating Area through the use of Automatic Generation Control;
- Maintain interconnected system reliability, through actions such as re-dispatch or curtailment;
- Support interconnected system frequency; or to
- Respond to transmission, generation or load contingencies.

For the purposes of Forecast Deviation Service, peak hours are between 07:00 and 23:00 Atlantic Time, Monday to Friday. All other hours are considered non-peak hours.

Each Licenced Retail Supplier shall use commercially reasonable efforts to provide accurate schedules and forecasts of production from renewable low-impact generators that are not dispatchable.

To the extent that such schedules or forecasts of hourly production of the aggregate of a Licenced Retail Supplier's RtR generation resources deviate from the actual production for reasons other than those that occur as a result of actions directed by the Operating Area operator the following charges shall apply:

An hourly deviation band of +/- 10 percent of the aggregate hourly scheduled or forecast quantity (with a minimum deviation band of +/- 2 MW) will be applied hourly to any forecast discrepancy that occurs as a result of the Transmission Customer's scheduled transaction(s).

- Hourly forecast discrepancies falling outside the hourly deviation band during peak hours will be charged at 10% of the average on-peak system marginal cost for the billing month.
- Hourly forecast discrepancies falling outside the hourly deviation band during non-peak hours will be charged at 10% of the average non-peak system marginal cost for the billing month.

## SCHEDULE 5: OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The charges, payable monthly, for Spinning Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

<u>Point-to-Point Transmission Service:</u>

| Point-to-Point Transmission Service | |
|---|---|
| **Delivery Period** | **Charge($)** |
| Yearly | One twelfth of $1,998.99/MW of Reserved Capacity per year |
| Monthly | $166.58/MW of Reserved Capacity per month |
| Weekly | $38.44/MW of Reserved Capacity per week |
| Daily | $5.48/MW of Reserved Capacity per day |

The minimum period for which this service is available from the Transmission Provider is one day.

<u>Network Integration Transmission Service:</u>

$166.58/MW of the Network Integration Transmission Service per month.

### Customer Obligations for Self-supply and Third-party Supply

The customer obligation for self-supply or third-party supply of Operating Reserve – Spinning Reserve is equal to 2.0 percent of the Transmission Customer's reserved capacity for Point-to-Point Transmission Service and 2.0 percent of the Network Load for Network Integration Transmission Service.

### Supplier Obligations

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

### Activation of Reserves

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers. This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Operating Reserve service will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

## SCHEDULE 6: OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service (also referred to as Contingency Reserve – Supplemental) is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Operating Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The charges, payable monthly, for Supplemental Reserve Service are set forth below. To the extent the Operating Area operator performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Operating Area operator.

Operating Reserve – Supplemental (10 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

| **Point-to-Point Transmission Service** | |
|---|---|
| **Delivery Period** | **Charge ($)** |
| Yearly | One twelfth of $3,981.98/MW of Reserved Capacity per year |
| Monthly | $331.83/MW of Reserved Capacity per month |
| Weekly | $76.58/MW of Reserved Capacity per week |
| Daily | $10.91/MW of Reserved Capacity per day |

Network Integration Transmission Service:

$331.83/MW of the Network Integration Transmission Service per month.

**Customer Obligations for Self-supply and Third-Party Supply**

The customer obligation for self-supply or third-party supply of Operating Reserve – Supplemental Reserve will be equal to 8.3 percent of Reserved Capacity for Point-to-Point Transmission Service and 8.3 percent of Network Load for Network Integration Transmission Service.

**Supplier Obligations**

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within eight minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for an additional 50 minutes.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

**Activation of Reserves**

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NSPI resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

Operating Reserve – Supplemental (30 minute):

Point-to-Point Transmission Service:

The minimum period for which this service is available from the Transmission Provider is one day.

| **Point-to-Point Transmission Service** | |
|---|---|
| **Delivery Period** | **Charge ($)** |
| Yearly | One twelfth of $3,374.81/MW of Reserved Capacity per year |
| Monthly | $281.23/MW of Reserved Capacity per month |
| Weekly | $64.90/MW of Reserved Capacity per week |
| Daily | $9.25/MW of Reserved Capacity per day |

Network Integration Transmission Service:

$281.23/MW of the Network Integration Transmission Service per month.

**Customer Obligations**

The customer obligation for reserves is equal to 3.0 percent of Reserved Capacity for Point-to-Point. Transmission Service and 3.0 percent of Network Load for Network Integration Transmission Service.

**Supplier Obligations**

Transmission Customers that self-supply this service, and third-party suppliers, shall provide between 100 and 110 percent of the stated MW amount within 30 minutes of notification by the Transmission Provider to activate these reserves. The reserves shall be sustainable for at least 60 minutes from the time of activation.

Suppliers who offer Operating Reserve have an obligation to supply these reserves when notified by the Transmission Provider. Due to the infrequent occurrence of this and the importance of reserves to overall system reliability, a penalty will be applied to any supplier who is unable to meet its obligations. The penalty will be equal to one month's charge for the amount of deficient reserves for each failure to supply.

**Activation of Reserves**

When a contingency occurs, the Transmission Provider will activate, at its sole discretion, sufficient reserves from (i) those under contract with the Transmission Provider, (ii) those provided by Transmission Customers, (iii) those contracted from third parties by Transmission Customers.

This includes, but is not restricted to, NS Power resources. Typically the activation will be done to minimize the overall cost of supplying reserves and to return the system to pre-contingency conditions within the time required by NPCC and NERC.

Reserve services will only be available for the hour in which the contingency occurs and the following two hours. The quality of service will be firm for this time period. The Transmission Customer is responsible to address any deficiency of its supply by the end of that time period. Any unscheduled energy withdrawal will be treated as Energy Imbalance as per Schedule 4.

## SCHEDULE 7: LONG-TERM FIRM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1. Yearly delivery: one-twelfth of the demand charge of $59,875.87/MW of Reserved Capacity per year.
2. Monthly delivery: $4,989.66/MW of Reserved Capacity per month.
3. Weekly delivery: $1,151.46/MW of Reserved Capacity per week.
4. On-Peak Daily delivery: $230.29/MW of Reserved Capacity per day.
5. Off-Peak Daily Delivery: $164.04/MW of Reserved Capacity per day

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 3 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

6. Discounts: Three principal requirements apply to discounts for transmission service as follows:

    (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

    (ii) any customer-initiated requests for discounts (including requests for use by one's Wholesale Merchant or an affiliate's use) must occur solely by posting on the OASIS, and

    (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

7. On-Peak days for this service are defined as Monday to Friday.

## SCHEDULE 8: NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: $4,989.66/MW of Reserved Capacity per month.

2. Weekly delivery: $1,151.46/MW of Reserved Capacity per week.

3. On-Peak Daily delivery: $230.29/MW of Reserved Capacity per day.

4. Off-Peak Daily Delivery: $164.04/MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any day during such week.

5. On-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $14.39/MWh.

6. Off-Peak Hourly delivery: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.84/MWh.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in Sec tion 3 above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in Section 2 above times the highest amount in megawatts of Reserved Capacity in any hour during such week.

7. Discounts: Three principal requirements apply to discounts for transmission service as follows:

    (iv) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS,

    (v) (ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and

    (vi) (iii) once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

8. On-Peak days for this service are defined as Monday to Friday.

9. On-Peak hours for this service are defined as time between hour ending 09:00 and hour ending 24:00 Atlantic Time, Monday to Friday.

## SCHEDULE 9: REAL POWER LOSS FACTORS

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak and off-peak hours to derive an average loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the system average loss factor of 2.78 percent. This factor will be reviewed annually and is subject to change annually. It will be posted on the OASIS.

Transmission Customers are required to provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

Locational Loss Factors for new generation will be determined during the System Impact Study and be applied to generation dispatch merit order if such generation is to be economically dispatched by the Transmission Provider. If the generator is self-dispatched, loss factors will be applied to determine the unit net output.

Locational Loss Factors for each generator will be determined on an annual basis and will be posted on the OASIS.

## SCHEDULE 10: NETWORK INTEGRATION TRANSMISSION SERVICE RATE

1. The rate charged for Network Integration Transmission Service is $4,241.21/MW-m, based on the Transmission Customer's Net Non-coincident Monthly Peak Demand.

2. Net Non-coincident Monthly Peak Demand is the maximum hourly demand at each Point of Delivery designated as Network Load (including its designated Network Load not physically interconnected to the Transmission Provider's Transmission System).

3. Transmission congestion charges will be applied as follows:

A = B x (C/D)

Where

A = the Network Customer's congestion charge for all hours of the month that congestion redispatch costs occurred.

B = Total redispatch costs during the month.

C = The Network Customer's load during the hours for which redispatch costs were incurred.

D = The sum of all Network Integration Transmission Service load (including load served by the Transmission Provider) and Point- to-Point Transmission Service scheduled serving load in the Operating area during the hours of the month for which redispatch costs were incurred.