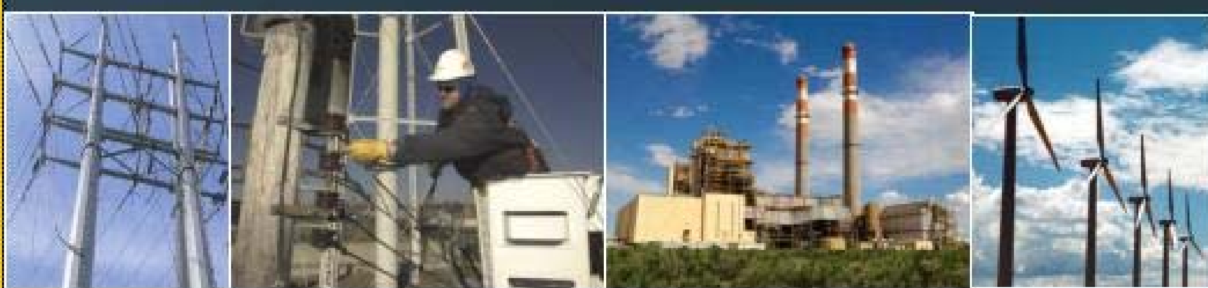

# *Guide to the Class Cost of Service Study (CCOSS)*
# *Northern States Power Co Electric*

## I. Overview

Simply stated, the purpose of the Northern States Power Company (NSP) electric Class Cost of Service (CCOSS) is to allocate ***joint*** (e.g.) and ***common*** costs to the designated "classes" of service such as Residential, Non-Demand C&I and Demand C&I. For example, generation capacity costs are "joint" between time periods and overhead costs such as management, are "common" to multiple functions, such as distribution, transmission and generation. The CCOSS also assigns ***direct*** costs (e.g. a dedicated service extensions or dedicated substations), that may be associated with providing service to a particular customer from a specific class of service. The objective of the CCOSS is to make these cost ***allocations*** and ***assignments*** based on identifiable service requirements (e.g. kWh energy requirements and kW capacity requirements), which are the drivers of the costs.

The two basic types of costs are; (1) capital costs associated with investment in generation, transmission and distribution facilities and (2) on-going expenses such as fuel used to produce the energy, labor costs and numerous other operating expenses. The end result is an allocation of the total utility costs (i.e. the revenue requirements) to customer classes according to each class' share of the capacity, energy and customer service requirements.

## II. Major Steps of the Class Cost of Service Study

A class cost of service study begins with a detailed documentation of the numerous budgetary elements of the total revenue requirement for the jurisdiction in question. The detailed jurisdictional revenue requirements are the data inputs to the CCOSS. At a high level, the CCOSS process consists of the following three (3) basic steps:

1. Functionalization – The identification of each cost element as one of the basic utility service "functions" (e.g. generation, transmission, distribution and customer).
2. Classification – The classification of the functionalized costs based on the billing component/determinant that each is associated with (e.g. kWs of capacity, kWhs of energy or number of customers).
3. Allocation – The allocation of the functionalized and classified costs to customer classes, based on each class' respective service requirements (e.g. kWs of capacity, kWhs of energy and the number of customers, expressed in terms of a percentage of the total jurisdiction requirement).

## III. Step 1: Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class' service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The 4 basic functions and the associated sub-functions are shown in the table below:

| Function | FERC Accounts | Sub-Function | Description |
|---|---|---|---|
| Generation | 120, 310-346, 500-557 | "Energy-related" | Includes the fixed costs of generation plant investment and purchase capacity costs, which have been stratified as "energy-related." |
| | | Summer "capacity-related." | Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system summer peak load requirements. |
| | | Winter "capacity-related." | Includes the fixed costs of generation plant investment and purchase capacity costs stratified as "capacity-related" and which are associated with the system winter peak load requirements. |
| | | On-Peak Energy | Includes costs for fuel and purchases of energy for on-peak hours. |
| | | Off-Peak Energy | Includes costs for the fuel and purchases of energy for off-peak hours. |
| Transmission | 350-359, 560-579 | None | Includes costs of transmission lines and associated substation facilities used to transport power from its origin generation stations or delivery points to the high voltage side of the distribution substations. |
| Distribution | 360-368, 580-598 | Distribution Substations | Includes costs of the facilities (e.g. transformers and switch gear) between the transmission and distribution systems. |
| | | Primary Distribution System "Capacity." | Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of primary voltage conductors, transformers and related facilities. |
| | | Secondary Distribution System "Capacity." | Includes costs of the "capacity" portion (as distinguished from the "customer" portion) of secondary voltage conductors, transformers, customer services and related facilities. |

| Function | FERC Accounts | Sub-Function | Description |
|---|---|---|---|
| Customer | 360-369, 580-598, 901-916 | "Customer" portion of the Primary and Secondary Systems | Includes costs for the "customer" portion of primary and secondary conductors, transformers, customer service drops, related facilities and the costs of metering. |
| | | Energy Services | Includes costs for meter reading, billing, customer service and information, and back office support. |

**A. Generation Cost Stratification**

Stratification is the term used to identify the part of the CCOSS process used to separate or "stratify" fixed generation costs into the necessary "capacity-related" and "energy-related" sub-functions. The "capacity-related" portion of the fixed costs of owned generation (and also of the purchased power contract costs) is based on the percent of total fixed costs of each generation type that is equivalent to the cost of a comparable peaking plant (the generation source with the lowest capital cost). The percent of total generation costs that exceeds the cost of a comparable peaking plant are sub-functionalized as "energy-related." This second portion of the fixed generation costs is "energy-related" because these costs are in excess of the "capacity-related" portion and as such were not incurred to obtain capacity but rather were incurred to obtain the lower cost energy that such plants can produce.

For example, the plant stratification analysis used in the current rate case is shown in the table below. It compares the then current-dollar replacement costs of each plant type, to develop stratification percentages.

| Plant Type | $/kW | Capacity Ratio | Capacity % | Energy % |
|---|---|---|---|---|
| Peaking | $689 | $689 / $689 | 100% | 0% |
| Nuclear | $3,678 | $689 / $3,678 | 18.7% | 81.3% |
| Fossil | $1,912 | $689 / $1,912 | 36.0% | 64.0% |
| Combined Cycle | $997 | $689 / $997 | 69.1% | 30.9% |
| Hydro | $4,474 | $689 / $4,474 | 15.4% | 84.6% |
| Wind | $16,989 | $689 / $16,989 | 4.1% | 95.9% |

This process of "stratifying" the revenue requirements of the generation plant is accomplished by applying these stratification percents to each component of the revenue requirements (e.g. book investment, accumulated depreciation, net plant, cost of capital, income taxes, etc.), for each generation plant type.

**B. Summer/Winter Split of Generation Capacity-Related Costs**

Once the "capacity-related" portion of generation plant costs have been quantified, they are further separated into summer and winter sub-functions. The seasonal sub-function portions are determined as follows.

First, the 12 monthly System peak loads are grouped into a 4-month summer (June, July, August and September) and an 8-month winter seasons. Second, the average hourly load for the year is subtracted from each monthly peak. Third, the remaining monthly excess loads are averaged for each season and the ratio of these two average seasonal "excess" loads is used to assign the "capacity- related" portion of fixed generation costs to the seasons. This calculation for the current rate case is shown below.

| (1) | (2) | (3) | (4) = (3) minus 5,411 |
|---|---|---|---|
| **Month** | **Season** | **Monthly NSP System Peak Load** | **Monthly Peak in Excess of Average Hourly Load** |
| Jan | Winter | 6,690 | 1,455 |
| Feb | Winter | 6,561 | 1,325 |
| Mar | Winter | 6,158 | 922 |
| Apr | Winter | 5,768 | 532 |
| May | Winter | 6,965 | 1,730 |
| Jun | Summer | 8,305 | 3,070 |
| Jul | Summer | 9,368 | 4,132 |
| Aug | Summer | 8,707 | 3,471 |
| Sep | Summer | 7,778 | 2,542 |
| Oct | Winter | 6,126 | 891 |
| Nov | Winter | 6,296 | 1,060 |
| Dec | Winter | 6,590 | 1,355 |
| | | | |
| **Average Annual Load** | | **5,236** | |
| | | | |
| **Average Monthly Excess** | | | |
| Average of Summer Months | | | 3,304 |
| Average of Winter Months | | | 1,159 |
| Total | | | 4,463 |
| | | | |
| Summer Percent | | | **74.04%** = 3,304/4,463 |
| Winter Percent | | | **25.96%** = 1,159 / 4,463. |

As shown above 74.04% of generation capacity costs were assigned to the summer season while 25.96% were assigned to winter, thereby separating total generation capacity-related costs into summer and winter seasons.

## IV. Step 2: Cost Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs. The 3 principle service requirements or billing components are:

1. Demand – Costs that are driven by the customer's maximum kilowatt ("kW") demand.
2. Energy – Costs that are driven by the customer's energy or kilowatt-hours ("kWh") requirements.
3. Customer – Costs that are related to the number of customers served.

The table below shows how each of the functional and sub-functional costs was classified:

| **Function/Sub-Function** | **Cost Classification** | | |
|---|---|---|---|
| | **Demand** | **Energy** | **Customer** |
| Summer Capacity-Related Fixed Generation | X | | |
| Winter Capacity-Related Fixed Generation | X | | |
| Energy-Related Fixed Generation | | X | |
| Off-Peak Energy (Fuel and Purchased Energy) | | X | |
| On-Peak Energy (Fuel and Purchased Energy) | | X | |
| Transmission | X | | |
| Distribution Substations | X | | |
| Primary Lines | X | | X |
| Primary Transformers | X | | |
| Secondary Lines | X | | X |
| Secondary Transformers | X | | X |
| Service Drops | X | | X |
| Metering | | | X |
| Customer? Services | | | X |

As shown in the table above, primary lines, primary transformers too; why won't they be?, secondary lines, secondary transformers and service drops are classified as both "demand" and "customer" related costs. Costs of these sub-functions are driven by **both** the number of customers on the distribution system and the capacity requirements they place on the system. The analysis used to separate these costs into demand and customer components is called the Minimum Distribution System (MDS) method.

The Minimum Distribution System method involves comparing the cost of the minimum size of each type of facility used, to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The table also shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

| **Equipment Type** | **% Classified as "Customer" Related** |
|---|---|
| Overhead Lines Primary | 42.2% |
| Primary Transformers | 0% |
| Overhead Lines Secondary | 54.9% |
| Underground Lines Primary | 85.9% |
| Underground Lines Secondary | 54.3% |
| Line Transformers Secondary | 48.8% |
| Services | 72.7% |

**V. Step 3: Cost Allocation to Customer Class (Assignment of Costs to Customer Classes)**

The third step in the CCOSS process is allocation, which is the process of assigning (allocating or directly assigning) functionalized and classified costs to customer classes. Generally, cost assignment occurs in one of 2 ways:

- Direct Assignment - A small but sometimes important portion of costs can be directly assigned to a specific customer of a particular customer class, because these costs can be exclusively identified as providing service to a particular customer. Examples of costs that are directly assigned include:
  - Customer-dedicated transmission radial lines or dedicated distribution substations
  - Street lighting facility costs
- Allocation - Most electric utility costs are incurred in common or jointly in providing service to all or most customers and classes. Therefore, allocation methods have to be developed for each functionalized and classified cost component. The allocation method is based on the particular measures of service that is indicative of what drives the costs.
  - Class allocators (sometimes called allocation strings) are simply a "string" of class percentages that sum to 100%.
  - There are 2 types of allocators:
    - External Allocators –These are the more interesting allocators that are based on data from outside the CCOSS model (e.g. load research data, metering and customer service-related cost ratios). In general, there are 3 types of external allocators:
      - Capacity –related (sometimes referred to as Demand) allocators such as:
        - System coincident peak (CP) responsibility or class contribution to system peak (1CP, 4CP or 12CP)
        - Class peak or non-coincident peak
        - Individual customer maximum demands
      - Energy-related allocators such as:
        - kWh at the customer (kWh sales)
        - kWh at the generator (kWh sales plus loses)
        - kWh energy, weighted by the variable cost of the energy
      - Customer-related allocators
        - Number of customers
        - Weighted number of customers, where the weights are based on cost of meters, billing, meter-reading, etc.

      Details on the external allocators used in the CCOSS model are shown in Appendix 1.

    - Internal Allocators – These are allocators based on combinations of costs already allocated to the classes using external allocators. These internal allocators are used to assign certain costs, which are most appropriately associated with and assigned to classes by some combination of other primary service requirements, such as kWs demand, kWhs of energy or the number of customers. Examples of internal allocators include:
      - PTD – Production, transmission and distribution plant investment.

- OXDTS – Distribution O&M expenses without supervision and miscellaneous expenses.

Details on the development of the internal allocators used in the CCOSS model are shown in Appendix 2.

**VI. Customer Class Definitions**

Ideally, there would be no customer class groupings and cost allocation would reflect the unique costs of each individual customer. Because this is not possible, it is necessary to develop a cost study process that identifies costs of service for groups of customers ("classes") where the customers of the class have similar cost/service characteristics. The basic classes of service employed in the Company's CCOSS are the following:

1. Residential
2. Non Demand Metered Commercial
3. Demand Metered Commercial & Industrial and
4. Street & Outdoor Lighting

Also, because of the significantly different distribution-functional requirements of customers within the Demand Metered C&I class, the Company's CCOSS also identifies the cost differences associated with the following distribution-function requirements within this class:

1. Secondary
2. Primary
3. Transmission Transformed
4. Transmission

More detail on customer class definitions is shown in Appendix 3.

**VII. CCOSS Data Inputs**

As noted earlier, there are a large number of inputs to the CCOSS model including detailed rate base and expense items from the Jurisdictional Cost of Service Study (JCOSS) as well as numerous inputs from other sources used to develop external allocators. A complete list of inputs to the CCOSS model is shown in Appendix 4

**VIII. Organization of the CCOSS Model**

The CCOSS model consists of numerous worksheets which show costs by customer class in Total (as shown on the worksheet tab labeled "TOT") and at the following more detailed levels including Billing Unit, Function and Sub-function as shown below:

1. Billing Unit:

    a. Customer (Cus)
    b. Demand (Dmd)
    c. Energy (Ene)

2. Function and Associated Sub-Function:

    a. Energy (Ene)

a) On-Peak Energy (On)
b) Off-Peak Energy (Off)

b. Generation (Gen_Dmd): Sub-functions include:
   a) Summer Capacity-Related Plant (Summ)
   b) Winter Capacity-Related Plant (Wint)
   c) Energy-Related Plant (Base)

c. Transmission (Transco)

d. Distribution (Disco): Sub-functions include:
   a) Distribution Substations (Psub)
   b) Primary Voltage? (Prim)
   c) Secondary Voltage? (Sec)

e. Customer (Cus): Sub-functions include:
   a) Service Drops (Svc_Drop)
   b) Energy Services (En_Svc)

In the CCOSS spreadsheet there is a separate worksheet tab for each of the above billing units, functions and sub-functions. The label for each worksheet tab is show in parentheses above. This multi-level breakdown of costs is useful for designing rates as well as for determining class revenue responsibilities.

## IX. CCOSS Calculations

Listed below are important calculations that are part of the CCOSS model. These calculations occur at the "TOT" layer of the CCOSS as well as each of the "sub-layers" for each billing component, function and sub-function. Showing results at the more detailed billing component, function and sub-function levels is important for rate design purposes, as well as other analyses such as the development of voltage discounts.

### A. Rate Base Calculation

**Rate Base** = Original Plant in Service – Accum. Depr + CWIP + Other Additions

The above rate base calculation occurs on "TOT" layer as well as each function/sub-function layer.

### B. Revenue Requirements Calculation (Class Cost Responsibility)

The Revenue Requirements Calculation (sometimes referred to as the "Backwards Revenue Requirement Calculation) is used to calculate "**cost"** responsibility for each customer class. This has to be done within the CCOSS model because the JCOSS model does it only at the total jurisdiction level, not by class. The class "**cost"** responsibility is based on the same return on rate base for each class that is equal to the overall proposed rate of return. In other words, class revenues requirements are calculated to provide the same return on rate base for each customer class. This calculation occurs on the "TOT" layer as well as for each function, sub-function and billing component after all expenses and rate base items have been allocated. As such, class cost responsibility is available for each function, sub-function and billing component. This analysis serves a starting point for rate design. The formula is shown below:

Retail Revenue Requirement = Expenses (including off-setting credits from Other Operating Revenues)
+
(Return on Equity x Rate Base) x 1 / (1-Tax Rate)
+
(Tax Additions – Tax Deductions) x Tax Rate / (1-Tax Rate) Mike what does this mean. Aren't income taxes already in the line above?
+
AFUDC

Where:

Expenses = O&M + Book Depreciation + Real Estate & Property Tax + Payroll Tax
+ Net Investment Tax Credit – Other Retail Revenue – Other Oper. Revenue

Tax Additions = Book Depreciation + Deferred Inc Tax + Net Inv Tax Credit
+ Other Misc Expenses .

Tax Deductions = Tax Depreciation + Interest Expense + Other Tax Timing Diff

**C. Total Return and Return on Rate Base (Based on Class Revenue Responsibility)**

After rates have been designed and each class' "**revenue"** responsibility has been determined, the model calculates total return and return on rate base using the following formulas. These calculations are performed at both present and proposed rate levels.

**Total $ Return** = Revenue – O&M Expenses – Book Depr.
– Real Estate & Property Taxes– Provision for Deferred Inc Taxes – Inv. Tax Credits
– State & Federal Income Taxes + AFUDC

**Percent Return on Rate Base** = Total $ Return / $ Rate Base

After rates have been designed, the return on rate base is typically different for each customer class. In other words, the resulting class "**revenue"** responsibility differs from class "**cost"** responsibility.

**XI. CCOSS Output**
The filed output of the CCOSS model includes the "Tot" worksheet layer of the much larger model. The important output from the functional, sub-functional and billing component layers is presented on pages 2 and 3 of this "TOT" layer. The following table lists what is shown on each CCOSS page when printed.

**Final CCOSS Printout "Tot" Worksheet**

| **CCOSS Section** | **Page Number** | **Results Detail** | **Line Numbers** |
|---|---|---|---|
| Results Summary | 1 | Rate Base Summary | 1-23 |
| | | Income Statement Summary | 24-34 |
| | 2 | **Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Present** Rate **Revenue** Responsibility | 1-51 |
| | 3 | **Proposed Cost** Responsibility at Equal ROR (the cost of service) compared to **Proposed** Rate **Revenue** Responsibility | 1-55 |
| Rate Base Detail | 4 | Original Plant in Service | 1-48 |
| | 5 | MINUS Accumulated Depreciation | 1-27 |
| | | MINUS Accumulated Deferred Income Tax | 28-56 |
| | 6 | PLUS Construction Work in Progress & Other Additions | 1-35 |
| | | EQUALS Total Rate Base | 36 |
| Income Statement Detail | 7 | Present and Proposed Revenues | 1-26 |
| | | MINUS O&M Expenses part 1 | 27-41 |
| | 8 | MINUS O&M Expenses part 2 | 1-34 |
| | 9 | MINUS Book Depreciation | 1-25 |
| | | MINUS Real Estate & Property Taxes | 26-53 |
| | 10 | MINUS Provision for Deferred Income Tax | 1-28 |
| | | MINUS Investment Tax Credit | 29-41 |
| | | EQUALS Present and Proposed Operating Income Before Income Taxes | 42A<br>42B |
| | 11 (Income Tax Calcs.) | Tax Additions | 31-37 |
| | | MINUS Tax Deductions | 1-30 |
| | | EQUALS Total Tax Adjustments | 38 |
| | | PLUS Present and Proposed Operating Income Before Income Taxes | FROM Page 10<br>42A<br>42B |
| | | EQUALS Present and Proposed Taxable Income | 39A<br>39B |
| | | MULTIPLIED BY State and Federal Tax Rates | |
| | | EQUALS Present and Proposed State and Federal Income Taxes | 40A<br>40B |
| | 11 (Total Return Calcs.) | Present and Proposed Operating Income Before Income Taxes | FROM Page 10, Rows 42A & 42B |
| | | MINUS Present and Proposed State and Federal Income Taxes | 40A<br>40B |
| | | EQUALS Present and Proposed Preliminary Return | 41A<br>41B |
| | | PLUS AFUDC (from page 12) | 42 |
| | | EQUALS Present and Proposed Total Return | 43A<br>43B |

**XI. CCOSS Output (continued)**

| CCOSS Section | Page Number | Results Detail | Line Numbers |
|---|---|---|---|
| Misc Calcs | 12 | AFUDC | 1-26 |
| | | Labor Allocator | 27-48 |
| | 13 | Backwards Revenue Calculations | 1-36 |
| Allocator Data | 14 | Internal Allocators and Associated Data | 1-33 |
| | 15 | External Allocators and Associated Data | 1-40 |
| Misc CCOSS Data Inputs | 16 | On Peak Energy Weighting Factor, Summer Factor, Minimum System Splits, Plant Stratification Data, Tax Rates, Capitol Structure, Etc. | 1-46 |

## XI. CCOSS Output (continued)

| CCOSS Section | Page Number | Results Detail | Line Numbers |
|---|---|---|---|
| Misc Calcs | 12 | AFUDC | 1-26 |
| | | Labor Allocator | 27-48 |
| | 13 | Backwards Revenue Calculations | 1-36 |
| Allocator Data | 14 | Internal Allocators and Associated Data | 1-32 |
| | 15 | External Allocators and Associated Data | 1-44 |
| Misc CCOSS Data Inputs | 16 | On Peak Energy Weighting Factor, Summer Factor, Minimum System Splits, Plant Stratification Data, Tax Rates, Capitol Structure, Etc. | 1-58 |

The table below lists and describes the external allocators used in the Class Cost of Service (CCOSS) model.

| Code | Allocator for: | Description | Allocator Rationale & Background |
|---|---|---|---|
| **C11** | **Connection charge revenues** | **Average monthly customers for the Test Year** | **Customer connection revenues are driven by number of customer services.** |
| C10 | Used to calculate C11 | C11 less automatic protective lighting and load management services. C11 less number of customers with a second service. | |
| C11WAF | Used to calculate C11WA allocator | Customer accounting cost weighting factors. The weighting factor for residential customers is set at 1.0. The weighting factors for other classes are defined relative to costs for residential. E.g., if a class were three times costlier, its factor would be 3.0. | Weighting factors are set so as to reflect the relative costs of meter reading, billing and providing customer service for different classes of customers. For example some rate schedules are significantly more complex requiring more sophisticated meter reading capabilities, billing systems and customer service staff. |
| **C11WA** | **Customer accounting costs** | **Average monthly customers weighted by each class' relative rating of customer accounting costs: C11 X C11WAF** | **<u>Customer accounting</u> costs are driven by number of customers and the complexity of their respective rate, billing issues and customer service requirements.** |
| C12 | Used to calculate C12WM allocator | Reflects actual number of meters. C11 with an adjusted street lighting customer count. Only selected street lighting rates are metered | |
| C12WMF | Used to calculate C12WM allocator | Average meter cost for each customer type | |
| **C12WM** | **Meter costs** | **Number of meters multiplied by each class' average meter costs: C12 X C12WMF** | **<u>Metering</u> costs are driven by the number of customers in each class and the respective metering costs.** |
| **C61PS** | **The "customer" (minimum system) portion of <u>primary</u> distribution line costs** | **Average monthly customers served at primary or secondary voltage. C11 less transmission transformed and transmission voltage customers** | **The number of customers served at secondary and primary voltages drives the customer related portion of <u>primary distribution line</u> costs. Transmission and Transmission Transformed voltage customers are excluded since they do not use the distribution system** |

| Code | Allocator for: | Derivation | Allocator Rationale & Background |
|---|---|---|---|
| **C62Sec** | **The "customer" (minimum system) portion of secondary (not primary) distribution line costs** | **Average monthly customers served at secondary voltage. C61PS less primary voltage customers** | **The number of customers served at secondary voltage drives the customer related portion of secondary distribution line costs. Transmission and primary voltage customers are excluded since they do not use the secondary distribution system.** |
| **C62NL** | **The "customer" (minimum system) portion of service-line costs.** | **Adjusted average monthly secondary voltage customers. C62Sec less street lighting and C&I underground customers** | **The number of secondary customers drives the customer portion of service line costs. C&I underground secondary customers are excluded since they own their services. Lighting customers are excluded since they do not have services.** |
| **D60Sub** | **Distribution substation costs** | **Class Coincident peak measured at the high voltage side of the Distribution Substation less Class Coincident peak of Transmission Voltage customers** | **Distribution substation costs are driven by class peak demands, whenever they occur which is generally at times other than the total system peak. Transmission voltage customers are excluded since they do not use the distribution substation.** |
| **D61PS** | **The capacity portion of primary distribution line costs.** | **D60Sub less Transmission Transformed customer demands, less customer demands served by minimum distribution system and with reduced Residential Space Heating demands to reflect the fact that their summer peak is less than their winter peak.** | **The driver of primary distribution line costs is the class coincident demands less the minimum system demand of each class. The minimum demand is classified as a customer related cost. Also transmission and transmission transformed voltage customers are excluded since they do not use the distribution system.** |
| D62Sec | Used to calculate the D62SecL allocator | D61PS less class coincident demands of primary voltage customers | |
| **D62SecL** | **The capacity portion of secondary distribution line costs** | **D62SecL equals the average of D62Sec percent and non-coincident (or "individual customer peak") secondary voltage percent.** | **Capacity related secondary distribution line costs are driven by both class coincident peak demand and individual customer maximum demand, less the minimum system demand of each class. (The minimum system demand is as customer related.) Also, transmission and primary voltage customers are excluded since they do not use the secondary distribution system.** |

| Code | Allocator For | Derivation | Allocator Rationale |
|---|---|---|---|
| D62NLL | The capacity portion of service-line costs | Non-coincident (or "customer peak") demand for secondary voltage customers, less the customer peak demand for street lighting, area lighting and C&I customers served underground | Capacity related service line costs are driven by individual customer maximum demands less the minimum system demand of each class. (The minimum system demand is customer related.) Transmission voltage, primary voltage and lighting customers are excluded since they do not cause service related costs. Also excluded are C&I underground customers since they install their own services. |
| D10S | Summer season portion of capacity-related generation costs | Each class' % contribution to the single summer system peak. Summer months are June through September. | The class contribution to the system summer peak drives the summer portion of capacity-related generation costs. |
| D10W | Winter season portion of capacity-related generation costs | Each class' % contribution to the single winter system peak. Winter months are October through May. | The class contribution to the system winter peak drives the winter portion of capacity-related generation costs. |
| D10T | Transmission plant costs. | Weighted Class Contributions to Summer and Winter Peak loads.<br><br>Allocator equals (D10W% plus (D10S% times 1.3355)) divided by (1 + 1.3355). The 1.3355 ratio is the ratio of the average summer and winter seasonal system peaks. | The driver for transmission costs is class contribution to the summer & winter system peaks. To reflect the fact that summer peaks have more impact, the summer peak contribution for each class is weighted by the ratio of average monthly summer and average monthly winter system peaks. |
| D10C | Capacity-related generation costs. | Weighted of Class Contributions to Summer and Winter system peak loads.<br><br>Allocator equals (D10W% plus (D10S% times 2.8514) divided by (1 + 2.8514). The 2.8514 ratio is obtained from the average summer and winter season peak loads, after subtracting the average annual load from each monthly load. | Capacity- related generation costs are driven by class contribution to summer & winter system peaks. To reflect the fact that summer peaks have a disproportionate impact on capacity-related generation costs, the summer peak is weighted by the ratio of average monthly summer and winter system peaks, which are in excess of average annual demand. |

| Code | Allocator For | Derivation | Allocator Rationale |
|---|---|---|---|
| **E8760** | **Energy-related portion of generation, nuclear fuel capital and generation step-up costs. Also allocator for fuel, purchased energy and energy-related fixed generation costs.** | **Class hourly energy (MWH) requirements multiplied by the corresponding hourly marginal energy cost.** | **The driver of these costs is energy requirements, which is measured by hourly energy requirements weighted by hourly marginal energy costs.** |

**Internal Allocators are those that are determined from data generated within the Class Cost of Service Study (CCOSS). Below is a list of internal allocators that are used within the CCOSS.**

| Code | Allocator for: | Description | Allocator rationale |
|---|---|---|---|
| C11P10 | Expenses and labor related to customer assistance and instructional advertising | This allocator is the average of the Customer-related C11 allocator and the Production Plant investment P10 allocator. | Customer assist. and advertising expenses are driven by # of customers and since most assistance pertains to helping customers reduce energy use it affects prod. plnt invest. |
| D56E44 | Economic development expenses | This allocator is based on the weighted average of the generation capacity and energy allocators. The weighting is based on an analysis of the fixed-cost-contribution margin of the General service tariff.<br><br>D56E44 = (% Demand Impacts x D10C) + (% Energy Impacts x E8760).<br><br>$ Energy Impacts = kWh sales x (Base Energy Charge + Fuel Costs – Marginal Energy Costs)<br><br>$ Demand Impacts = Annual Billing kW x (((4 x Summer Demand Charge)+ (8 x Winter Demand Charge))/12)<br><br>The demand portion is further split between Summer and Winter based on D10C; the energy portion is already split between on-peak and off-peak because E8760 is split that way.<br><br>Total $ Impacts = $ Energy Impacts + $ Demand Impacts | Minn. Stat. §216B.16, subd. 13 (1992) permits the Commission to allow utilities to recover economic development expenses. Pursuant to Docket No: E-002/GR-91-1, the Commission allowed NSP to recover 50% of its economic development expenses.<br><br>Economic development program costs and benefits are assumed to be a function of the fixed cost (margin) contribution of the demand and energy charges that result from the ED program. |
| D42E58 | CIP expenses | D48E52 = (.4172 x D10C)+(.5828 x E8760). | CIP program expenses are split between capacity and energy according to whether the purpose of program is to reduce peak load or energy requirements. Once program costs are thus split, the standard capacity and energy allocators are applied to the separate pools of $ expenses. |
| LABOR | Amortizations, Payroll Taxes and A&G Expenses that are labor related such as Salaries, Pension & Benefits, Injuries & Claims. | Total Labor costs on Page 12 line 48 less A&G Labor on Page 12 line 46. A&G Labor is excluded to avoid a circular reference. | The specified expenses are directly related to Labor costs. |

| Code | Allocator for: | Description | Allocator rationale |
|---|---|---|---|
| NEPIS | Property Insurance | Electric plant in service less accumulated provision for depreciation | Property insurance is driven by net electric plant in service |
| OXDTS | Distribution customer installation expenses and miscellaneous distribution expense. | All Distribution O&M Expense, except Supervision and Engineering, Customer Install and Miscellaneous. Supervision & engineering expenses are excluded since they are an overhead expense. Customer installation expenses and miscellaneous distribution expense are excluded to avoid a circular reference. (lines 2 thru 7, 9 and 11 of page 8) | The OXDTS allocator represents the majority of Distribution O&M expenses (excl supervision and customer installation costs) which is a good indicator for miscellaneous distribution expenses. |
| OXOPD | Used to allocate Capacity-Related Other Production labor costs | Capacity related "Other Production" expenses: Peaking + Base Load (line 37 of page 7) | Capacity-Related Other Production O&M costs are a good indicator of Capacity-Related Production Other Production labor |
| OXTS | Selected administrative and general expenses such as Office Supplies, General Advertising, Contributions and maintenance of "General" plant. | All O&M costs except Regulatory Expense and any A&G costs, which are the costs to be allocated on OXTS (lines 40 & 41 of page 7 and lines 12-15, 18-21, 32 and 33 of page 8). These A&G expenses are excluded to avoid circular references | The OXTS allocator includes all O&M expenses except regulatory expense and those A&G items that are allocated with OXTS. Representing most O&M expenses, the OXTS allocator is appropriate for allocating A&G expenses. |
| P10 | Interchange Production Capacity (i.e. fixed) inter-company Revenues. Rate base addition production-related materials and supplies. | Total Production Plant: Original Plant in Service (line 6 of page 4) | Total production plant investment is closely associated with Interchange Agreement Capacity related revenues |
| P10WoN | Interchange Production Capacity (i.e. fixed) inter-company Costs | Total Production Plant less Nuclear Fuel: Original Plant in Service. Nuclear fuel is excluded since NSP Wisconsin does not have nuclear plants (Total Production Plant on line 6 of page 4 less Nuclear Fuel on line 5 of page 4) | Since Wisc. does not have nuclear plants, Total production plant investment less nuclear fuel investment is a good indicator of Interchange Agreement Capacity related expenses |
| P5161A | Used to allocate Step-up sub transmission labor costs | Total Generation Set-Up Transformer original plant in service: Tran Gener Step Up (line 9 of page 4) + Distrib Substn Step Up (line 14 of page 4) | Generation step-up plant investment drives step-up generation labor costs |
| P61 | Distribution Substation O&M expense and Distribution Substation labor | Distribution Plant: Substations<br>Original Plant in Service (line 18, page 4) | Substation plant original investment drives Distribution Substation plant O&M costs and Distribution Substation Labor. |
| P68 | All costs related to Distribution Plant "Line Transformers" | Distribution Plant: Line Transformers<br>Original Plant in Service (line 37 of page 4) | Line transformer plant investment drives all line transformer costs. |
| P69 | All costs related to Distribution Plant "Services" | Customer-Connection "Services" Original Plant in Service (line 40 of page 4) | Distribution "Services" plant investment drives all costs of "Services" |

| Code | Allocator for: | Derivation | Allocator rationale |
|---|---|---|---|
| P73 | All costs related to Street Lighting | Street Lighting Original Plant in Service (line 42 of page 4) | Street Lighting plant investment drives all Street Lighting costs.. |
| POL | All costs related to Overhead Distribution Lines including Rental costs and Distribution overhead line rent revenues. | Distribution Plant: Overhead Lines Original Plant in Service (line 26 of page 4) | Overhead distribution line plant investment drives all costs related to Overhead Distribution Lines. |
| PT0 | Working Cash | Total Real Estate & Property Taxes (line 50 of page 9) | Working Cash is closely related to Real Estate Taxes |
| PTD | All costs related to General Plant and Electric Common Plant | Production + Transmission + Distribution Plant Original Plant Investment (lines 6, 13 and 43 of page 4) | Total investment in production, transmission and distribution plant is the best allocator for general and common plant. |
| PUL | All costs related to Underground Distribution Lines | Distribution Plant: Underground Lines Original Plant in Service (line 33 of page 4) | Underground distribution line plant investment drives all costs related to Underground Distribution Lines. |
| RTBASE | Income Tax Addition: Avoided tax interest | Total Rate Base (line 36 of page 6) | Total rate base drives avoided tax interest |
| TD | Transmission and Distribution Materials and Supplies that are Rate Base Additions | Total Transmission and Distribution Original Plant in Service (Lines 13 and 43 of page 4) | Total Transmission and distribution plant investment drives investment in miscellaneous transmission and distribution materials and supplies |
| ZDTS | Supervision & Engineering and Customer Installation Distribution Labor | All Distribution Labor except Supervision and Engineering and Customer Installation. These items are excluded to avoid a circular reference. (All of lines 33 thru 42 on page 12, except lines 33 and 40) | Distribution labor (excluding Supervision & Engineering) drives Supervision and Engineering and Customer Installation Labor. |

# Exhibit___(MAP-1), Schedule 2
# Appendix 3: CCOSS Customer Classes Vs Tariff Cross Reference

### A. <u>Summary</u> Customer Classes

| | Customer Class | Rate Codes | Voltage Specifications |
|---|---|---|---|
| 1 | Residential | E01, E02, E03, E04, E06, E10 (if residential), E11 (if residential) | |
| 2 | C&I Non Demand Metered | E10 (if C&I), E11 (if C&I), E13, E14, E18 | |
| 3 | C&I Secondary Voltage | E15, E16, E20, E21, E22 | Secondary |
| 4 | C&I Primary Voltage | E15, E16, E20, E21, E22 | Primary |
| 5 | C&I Transmission Transformed Voltage * | E15, E16, E20, E21, E22 | Transmission Transformed |
| 6 | C&I Transmission Voltage * | E15, E16, E20, E21, E22 | Transmission |
| 7 | Street Lighting | E12, E30, E31, E32, E33 | |

### B. <u>Detailed</u> Customer Sub-Classes

| | Customer Class | Rate Codes | kW Size | Voltage Specifications |
|---|---|---|---|---|
| 1 | Residential without Space Heating | E01, E02, E03, E04 | | |
| 2 | Residential with Space Heating | E01, E02, E03, E04 | | |
| 3 | Load Management | E06, E10, E11 | | |
| 4 | Small C&I Non Demand Metered | E13, E14, E18 | | |
| 5 | Small C&I Secondary Voltage | E15, E16 | < 1,000 kW | Secondary |
| 6 | Small C&I Primary Voltage | E15, E16 | < 1,000 kW | Primary |
| 7 | Small C&I Transmission Transformed Voltage * | E15, E16 | < 1,000 kW | Transmission Transformed |
| 8 | Small C&I Transmission Voltage * | E15, E16 | < 1,000 kW | Transmission |
| 9 | Large C&I Secondary Voltage | E15, E16 | > 1,000 kW | Secondary |
| 10 | Large C&I Primary Voltage | E15, E16 | > 1,000 kW | Primary |
| 11 | Large C&I Transmission Transformed Voltage * | E15, E16 | > 1,000 kW | Transmission Transformed |
| 12 | Large C&I Transmission Voltage * | E15, E16 | > 1,000 kW | Transmission |
| 13 | Interruptible All Voltages | E20, E21, E22 | | All Voltages |
| 14 | Street Lighting – Company Owned | E30 | | |
| 15 | Street Lighting – Customer Owned | E31, E32, E33 | | |
| 16 | Auto Protective Lighting | E12 | | |

* Note: Currently there are no Xcel Energy customers in South Dakota that are served at Transmission Transformed or Tranmission Voltages