CHAPTER 8100
DEPARTMENT OF REVENUE
PROPERTY EQUALIZATION DIVISION
AD VALOREM TAXES; UTILITIES

8100.0100 DEFINITIONS.

Subpart 1. **Scope.** As used in this chapter, the following words, terms, and phrases shall have the meanings given to them by this part, except where the context clearly indicates a different meaning.

Subp. 2. **Allocation.** "Allocation" means the process of dividing the unit value of a utility company among the states in which the utility operates.

Subp. 3. **Apportionment.** "Apportionment" means the process of distributing that portion of the utility company's unit value which has been allocated to Minnesota to the various taxing districts in which the utility company operates.

Subp. 4. **Book depreciation.** "Book depreciation" means the depreciation shown by a utility company on its corporate books, and allowed the company by various regulatory agencies.

Subp. 5. **Capitalization rate.** "Capitalization rate" means the relationship of income to capital investment or value, expressed as a percentage.

Subp. 6. **Electric company.** "Electric company" means any company engaged in the generation, transmission, or distribution of electric power, excluding cooperatives and municipal corporations.

Subp. 7. **Gas distribution company.** "Gas distribution company" means any company engaged in the distribution of natural or synthetic gas, excluding the cooperatives and municipal corporations.

Subp. 8. **Installed capacity.** "Installed capacity" means the number of kilowatts a power plant is capable of producing as shown by the nameplates affixed to the generators by the manufacturer.

Subp. 9. **Integrated company.** "Integrated company" means any company engaged in two or more utility operations within Minnesota, such as electric distribution and gas distribution, within the framework of one corporate structure.

Subp. 10. **Major generating plant.** "Major generating plant" means any steam-electric power plant capable of generating 25,000 KW (kilowatts) or more; or any hydroelectric, internal combustion, or gas turbine power plant capable of generating 10,000 KW or more.

Subp. 11. **Net operating earnings.** "Net operating earnings" means earnings from the system plant of the utility after the deduction of operating expenses, depreciation, and taxes, but before any deduction for interest.

Subp. 12. **Non-formula-assessed property.** "Non-formula-assessed property" means property of a utility which is valued by the local or county assessor rather than by the commissioner of revenue.

Subp. 13. **Operating property.** "Operating property" means any property, owned or leased, except land that is directly associated with the generation, transmission, or distribution of electricity, natural gas, gasoline, petroleum products, or crude oil. Examples of operating property include, but are not limited to, substations, transmission and distribution lines, generating plants, and pipelines.

Land, garages, warehouses, office buildings, pole yards, radio communication towers, and parking lots are examples of nonoperating property.

Subp. 14. **Pipeline company.** "Pipeline company" means any company engaged in the transmission of natural gas, gasoline, petroleum products, or crude oil via a fixed line of pipes.

Subp. 15. **System plant.** "System plant" means the total tangible property, real and personal, of a company which is used in its utility operations in all states in which it operates.

Subp. 16. **Throughput.** "Throughput" means the amount of product measured in barrels, gallons, or cubic feet which passes through a pipeline.

Subp. 17. **Unit value.** "Unit value" means the value of the system plant of a utility company taken as a whole without any regard to the value of its component parts.

Subp. 18. **Weighted pipeline miles.** "Weighted pipeline miles" means the product obtained by multiplying the number of miles of each size of a pipeline by the diameter in inches of each size. Example: a six-mile pipeline three miles of which is ten inches in diameter and three miles of which is 30 inches in diameter would have a weighted miles product of 120.

Statutory Authority: *MS s 270.06 cl (14)*

8100.0200 INTRODUCTION.

The commissioner of revenue will estimate the valuation of the entire system of a utility company operating within the state. The entire system will be valued as a unit instead of valuing the component parts, utilizing data relating to the cost of the property and the earnings of the company owning or operating the property. The resulting valuation will be allocated or assigned to each state in which the utility company operates. Finally, by the process of apportionment, the portion allocated to Minnesota will be distributed to the various taxing districts within the state. Most of the data used in the valuation, allocation, and apportionment process will be drawn from reports submitted to the Department of Revenue by the utility companies. These reports will include Minnesota Department of Revenue Annual Utility Reports (UTL forms), Annual Reports to the Federal Energy Regulatory Commission and Annual Reports to the Interstate Commerce Commission. Periodic examinations of the supporting data for these reports will be made by the Department of Revenue.

The methods, procedures, indicators of value, capitalization rates, weighting percents, and allocation factors will be used as described in parts 8100.0300 to 8100.0600 for 1986 and subsequent years.

As in all property valuations the commissioner of revenue reserves the right to exercise his or her judgment whenever the circumstances of a valuation estimate dictate the need for it.

Statutory Authority: *MS s 270.06 cl (14)*

History: *11 SR 635*

8100.0300 VALUATION.

Subpart 1. **General.** Because of the unique character of public utility companies, such as being subject to stringent government regulations over operations and earnings, the traditional approaches to valuation estimates of property (cost, capitalized income, and market) must be modified when utility property is valued. Consequently, for the 1986 and subsequent assessment years, the value of utility company property will be estimated in the manner provided in this chapter.

Subp. 2. **Market approach.** Market value implies a price for which an entire public utility enterprise might reasonably change hands between willing and informed buyers and sellers. The term presupposes a market of normal activity,

no urgency to buy or sell on the part of either the buyer or seller, and continued operation of the utility as a single entity. Public utility property is seldom transferred as a whole unit under these circumstances. Consequently, after consideration of this approach, it has been decided that valuation of utility properties by this approach is speculative and unreliable and will not be employed as a method of valuation for utility property at this time.

Subp. 3. **Cost approach.** The cost factor to be considered in the utility valuation formula is the original cost less depreciation of the system plant, plus improvements to the system plant, plus the original cost of construction work in progress on the assessment date. The original cost of any leased operating property used by the utility must be reported to the commissioner in conjunction with the annual utility report. If the original cost of the leased operating property is not available, the commissioner shall make an estimate of the cost by capitalizing the lease payments. Depreciation will not be allowed on construction work in progress. Depreciation will be allowed as a deduction from cost in the amount allowed on the accounting records of the utility company, as such records are required to be maintained by the appropriate regulatory agency.

Depreciation, however, shall not exceed the prescribed percentage of cost: for electric companies, 20 percent; for gas distribution companies, 50 percent; and for pipeline companies, 50 percent. If the amount of depreciation shown on the company's books exceeds these percentages, the company may deduct ten percent of the excess.

A modification to the cost approach to value will be considered by the commissioner when valuing electric utility property. The original cost of an electric utility's major generating plants will be increased if the cost of the plant falls below a certain standard. The standard to be used will be a national average of the cost per kilowatt of installed capacity. The cost per kilowatt of installed capacity is the total construction cost of the generating plant divided by the number of kilowatts the plant is capable of producing. The national average to be used will be computed by totaling the construction costs, excluding the cost of land, for major generating plants within the 48 contiguous United States. The total cost of the plants will be divided by the total generating capacity of the same plants to arrive at an average cost per kilowatt of installed capacity. A separate average will be computed for each type of plant: gas turbine, hydroelectric, and steam-electric. The plants used in the calculation will exclude nuclear electric generating plants.

The information used to compute the average will be drawn from the latest issue of the United States Department of Energy publication, Historical Plant Cost and Annual Production Expenses for Selected Electric Plants. All plants included in this publication will be used in the computation of the national average by type of plant.

An example of this computation of the national average cost per kilowatt of installed capacity is as follows:

Steam-Electric Generating Plants

Plant	Plant Cost Excluding Land	Plant Capacity
A	$ 14,000,000	100,000 kw
B	13,000,000	90,000 kw
C	17,000,000	110,000 kw
D	14,500,000	80,000 kw
E	18,000,000	120,000 kw
F	10,000,000	70,000 kw
G	19,000,000	130,000 kw
H	9,000,000	60,000 kw
I	20,000,000	140,000 kw

J	8,000,000	50,000 kw
	$142,500,000	950,000 kw

Total plant cost ($142,500,000) divided by total plant capacity (950,000 kw) equals $150 average cost per kilowatt of installed capacity.

The national average cost per kilowatt of installed capacity will be compared to the specific cost per kilowatt of installed capacity for each of the major generating plants owned by the utility being valued. If the national average cost per kilowatt is greater than the subject plant cost, the subject plant will have additional dollars incorporated into its cost in order to raise its cost per kilowatt to the national average. If the subject plant's cost per kilowatt equals or exceeds the national average, no cost will be added.

The following example illustrates this procedure:

XYZ Utility

Steam-Electric Generating Plants

1.	Plant	#1	#2
2.	Installed Capacity	100,000 kw	50,000 kw
3.	Year in Service	1970	1950
4.	Cost of Plant (Exclusive of Land)	$15,200,000	$5,000,000
5.	Specific Plant Cost per kw	$152	$100
6.	National Average Cost per kw	$150	$150
7.	Deficiency	none	$ 50
8.	Additional Cost (Line 7 x Line 2)	none	$2,500,000

This additional cost to be added to the original cost of the specific plant will be reduced by an allowance for pollution control equipment and an allowance for obsolescence.

The allowance for pollution control equipment will be computed annually by totaling the construction costs, exclusive of land, of all major generating plants within Minnesota by type of plant. A total will also be made of the cost of the equipment in these plants which has been approved for tax exempt status in accordance with Minnesota Statutes, section 272.02, subdivision 1, clause (9). This total will also be computed by type of plant. The total of the approved pollution control equipment will be divided by the total construction cost, exclusive of land, of the plants in order to calculate a percentage. This percentage will be the ratio of dollars spent for pollution control equipment to total dollars spent to construct a specific type of power plant. This percentage will then be used to reduce the gross additional cost to be added to the cost of the specific generating plant. An example of this process is as follows:

Steam-Electric Plants Within Minnesota

Plant	Plant Cost Excluding Land	Cost of Approved Pollution Control Equipment
A	$15,200,000	$1,500,000
B	10,000,000	1,000,000
C	5,000,000	700,000
D	20,000,000	2,000,000
E	16,500,000	1,470,000
	$66,700,000	$6,670,000

Total cost of approved pollution control equipment ($6,670,000) divided by

total plant cost ($66,700,000) equals ten percent ratio of pollution control equipment expenditures to total expenditures for generating plant construction.

XYZ Utility

Steam-Electric Plant #2

1.	Additional Cost Due to Computation of Average Cost per kw of Installed Capacity	$2,500,000
2.	10% Allowance for Pollution Control Equipment	250,000
3.	Additional Cost to be Added after Adjustment for Pollution Control Equipment	2,250,000

The allowance for obsolescence which will be applied to the additional plant construction cost will be computed annually for hydroelectric and steam-electric generating plants. The information needed to compute the obsolescence factors will be drawn from the same publication that is used to compute the national average cost per kilowatt of installed capacity figure. Gas turbine plants will not have any obsolescence allowance applied to the additional cost added to the plants.

The obsolescence allowance for hydroelectric plants will be calculated through the use of a "plant factor." The plant factor is computed by dividing the number of kilowatt hours a generating plant actually produced in a year by the number of kilowatt hours the plant was capable of producing. The plant factor is normally expressed as a percentage. The mathematical expression of this factor is: net generation (kwh) divided by annual installed capacity (hours in a year multiplied by installed capacity (kw)). A standard plant factor will be computed for hydroelectric plants by averaging the plant factors of the ten plants with the highest plant factors in the average cost per kilowatt of installed capacity study. This standard will then be compared to an average of the most recent three years' plant factor of the subject plant. The amount the subject plant deviates from the standard is the amount of obsolescence which will be applied to the added cost.

An example of this obsolescence allowance computation is shown below.

Hydroelectric Plants

Plant	Net Generation kwh (000)	Plant Capability kwh (000)	Plant Factor
A	400,150	755,000	53 %
B	300,040	577,000	52 %
C	250,000	480,000	52 %
D	600,000	1,250,000	48 %
E	896,000	1,600,000	56 %
F	700,000	1,400,000	50 %
G	507,000	975,000	52 %
H	450,000	1,000,000	45 %
I	376,000	800,000	47 %
J	810,000	1,800,000	45 %
		Average	50 %

XYZ Utility

Hydroelectric Plant #4

Year	Net Generation kwh (000)	Plant Capability kwh (000)	Plant Factor

19XX	400,000	1,000,000	40 %
19XX	500,000	1,000,000	50 %
19XX	450,000	1,000,000	45 %
		Average	45 %

Hydroelectric plant #4 plant factor (45 percent) divided by standard plant factor (50 percent) equals 90 percent. Therefore, hydroelectric plant #4 deviates from the standard by ten percent, or is ten percent obsolete.

The obsolescence allowance for steam-electric generating plants will be computed annually using two indicators. The first indicator will be the plant factor. The plant factor for steam-electric plants will be computed and applied in the same manner as the computation specified for hydroelectric plants. The only difference will be that the information used for the computation will be drawn from the latest Fossil-Fueled Steam-Electric Plant Section of the latest Historical Plant Cost and Annual Production and Expenses for Selected Electric Plants publication rather than the Hydro-Electric Plant section. Plant factors of the ten best steam-electric generating plants within the study period will be averaged. This average will be compared to the most recent three-year average plant factor for the subject plant. The subject plant's deviation from the standard plant factor is the amount of indicated obsolescence.

The second indicator which will be used to compute an obsolescence allowance for steam-electric generating plants will be a thermal efficiency factor. The source of information for this computation will also be the latest issue of the United States Department of Energy's publication, Historical Plant Cost and Annual Production Expenses for Selected Electric Plants, Fossil-Fueled Steam Electric Plant Section. Thermal efficiency for a generating plant is measured by the number of British thermal units (Btu's) required to produce one kilowatt hour. This efficiency rating can be obtained by dividing the number of kilowatt hours produced by a generating plant by the number of Btu's needed to produce this power. The number of Btu's used can be obtained by multiplying the units of fuel burned by the generating plant - tons of coal, gallons of oil, or cubic feet of gas - by the average Btu content of the fuel unit. The standard thermal efficiency factor will be computed by averaging the thermal efficiency factor of the ten most efficient steam-electric generating plants within the study period used to compute the average cost per kilowatt of installed capacity. This standard thermal efficiency factor will then be compared to the thermal efficiency factor of the subject plant. The amount the subject plant deviates from the standard is the amount of obsolescence indicated by this factor.

The two obsolescence figures for the subject plant as indicated by both the plant and thermal efficiency factors will then be averaged. This resulting average is the obsolescence allowance which will be applied to the cost added to the subject plant as a result of the average cost per kilowatt of installed capacity computation. In no instance shall the original cost of a generating plant be reduced by an allowance for obsolescence unless its cost is increased through the use of the average cost per kilowatt of installed capacity computation. For the 1986 and subsequent assessments the additional cost after adjustments for obsolescence to be added to the cost indicator of value will be multiplied by 85 percent.

The following examples illustrate computation of the standard thermal efficiency factor; obsolescence indicated by the application of this factor to the subject plant; average obsolescence for steam-electric generating plants; and obsolescence allowance adjustment of the added cost due to the use of the average cost per kilowatt of installed capacity for the subject plant.

Steam-Electric Generating Plants

Plant	Net Generation kwh (Millions)	Btu's Used (Millions)	Btu's per kwh

A	2,000	18,400,000	9,200
B	6,000	53,400,000	8,900
C	8,000	72,000,000	9,000
D	5,000	45,500,000	9,100
E	3,000	26,400,000	8,800
F	1,000	9,000,000	9,000
G	4,000	36,600,000	9,150
H	9,000	80,550,000	8,950
I	7,000	61,950,000	8,850
J	5,000	45,250,000	9,050
			Average 9,000

XYZ Utility Company

Steam-Electric Plant #2

Net Generation kwh (Millions)	Btu's Used (Millions)	Btu's per kwh
2,000	21,600,000	10,800

Steam-electric plant #2 thermal efficiency factor (10,800 Btu's per kwh) divided by standard thermal efficiency factor (9,000 Btu's per kwh) equals 120 percent. Therefore, steam-electric plant #2 deviates from the standard by 20 percent or is 20 percent obsolete.

XYZ Utility Company

Steam-Electric Plant #2

1.	Obsolescence Indicated by Plant Factor	10%
2.	Obsolescence Indicated by Thermal Efficiency Factor	20%
3.	Obsolescence Allowance (Average of 1 and 2)	15%
4.	Additional Cost due to Computation of Average Cost per kw of Installed Capacity	$2,500,000
5.	15% Obsolescence Allowance	375,000
6.	Additional Cost to be Added after Adjustment for Obsolescence	2,125,000
7.	Adjustment factor	85%
8.	Net additional cost to be added	$1,806,250

The cost indicator of value computed in accordance with this subpart will be weighted for each type of utility company as follows: electric companies, 85 percent; gas distribution companies, 75 percent; and pipeline companies, 75 percent.

The following example illustrates how the cost indicator of value would be computed for an electric company:

1.	Utility Plant	$200,000,000
2.	Construction Work in Progress	5,500,000
3.	Additional Value from Average Cost Per KW Computation After Factoring	2,000,000
4.	Total Plant	207,500,000
5.	Nondepreciable Plant (Land, Intangibles, C.W.I.P.)	$ 17,500,000
6.	Depreciable Plant	190,000,000
7.	Book Depreciation	$40,000,000
8.	Maximum Depreciation (20%)	38,000,000
9.	10% Excess Depreciation Allowance	200,000
10.	Total Allowable Depreciation	$ 38,200,000
11.	Total Cost Indicator of Value	169,300,000

Any company for which a modification is made under this subpart due to the average cost per kilowatt adjustment being made to original cost of a plant or plants located in Minnesota shall have an alternative cost indicator computation made without giving effect to the average cost per kilowatt adjustment of such plant or plants.

Subp. 4. **Income approach to valuation.** The income indicator of value will be estimated by weighting the net operating earnings of the utility company for the most recent three years as follows: most recent year, 40 percent; previous year, 35 percent; and final year, 25 percent. After considering, as far as possible, all conditions that may exist in the future that may affect the present annual return, including risk, life expectancy of the property, and cost of money, the capitalization rates used to compute value for the assessment will be: electric companies, 11.25 percent; gas distribution companies, 11.50 percent; and pipeline companies, 11.75 percent. The income indicator of value computed in accordance with this subpart will be weighted for each class of utility company as follows: electric companies, 15 percent; gas distribution companies, 25 percent; and pipeline companies, 25 percent.

The following example illustrates how the income indicator of value would be computed for a gas distribution company:

		1982	1983	1984
1.	Net Operating Income	$ 596,160	$ 488,911	$ 579,600
2.	Capitalized Income @ 11.5%	5,184,000	4,251,400	5,040,000
3.	Weighting Factor	25 percent	35 percent	40 percent
4.	Weighted Capitalized Income	1,296,000	1,488,000	2,016,000
5.	Total Income Indicator of Value			4,800,000

Subp. 5. **Unit value computation.** The unit value of the utility company will be the total of the weighted indicators of value.

The following is an example of the computation of the unit value for a gas distribution company:

1. Cost Indicator of Value:

$5,000,000 x 75% = $3,750,000

2. Income Indicator of Value:

$4,800,000 x 25% = $1,200,000

3. Unit Value of Gas Distribution Company:

100% $4,950,000

Any company whose cost indicator was modified under subpart 3 to reflect the average cost per kilowatt adjustment of a plant or plants located in Minnesota shall have an alternative unit value computation made without giving effect to the modification in respect of such plant or plants.

Subp. 6. **Valuation of utility property of cooperatives and other noncommon carrier or nonregulated utilities.** Cooperative associations and other types of utilities which do not operate in the traditional profit-making mode, are not common carriers, or are nonregulated, will have their utility property valued on the basis of historical cost only. Depreciation will be allowed as a deduction from the historical cost in increments of 2-1/2 percent per year, but the maximum depreciation allowed shall not exceed 25 percent of the cost of the utility operating property. Additions to existing utility property will be depreciated 2-1/2

percent per year until they reach the 25 percent maximum. Retirements of utility property will be deducted from the cost basis at the appropriate depreciation level of the retired property.

The following example illustrates this process for an electric cooperative association:

1.	Cost of Substation	$1,000,000
2.	Value 1st year @ 97.5%	975,000
3.	Value 2nd year @ 95%	950,000
4.	Value 3rd year @ 92.5%	925,000
5.	Value 4th year @ 90%	900,000
6.	Value 5th year @ 87.5%	875,000
7.	Value 6th year @ 85%	850,000
8.	Value 7th year @ 82.5%	825,000
9.	Value 8th year @ 80%	800,000
10.	Value 9th year @ 77.5%	775,000
11.	Value 10th year @ 75%	750,000
12.	Value 11th and succeeding years at 75%	750,000

Subp. 7. **Obsolescence allowances.** The commissioner shall adjust the value calculated under this part through the use of an obsolescence allowance. This allowance is intended to be used in order to recognize the effect the curtailment or termination of a pipeline's source of supply may have on its value. This allowance must be applied for each year at the time the utility files its Minnesota Department of Revenue Annual Utility Report. The utility's eligibility for this allowance will be based on the relevant facts for the specific valuation year. The application of an obsolescence allowance in any previous year shall have no bearing on the use of the allowance for a subsequent year. In order for a pipeline or a gas distribution company to be eligible for this allowance it must meet certain criteria or standards listed below. It is mandatory that standards in items A, B, and C be met by the utility. It is highly desirable that standards in items D and E also be met.

A. The utility shall demonstrate that its source of supply for gas or oil will be terminated within the next ten years.

B. The utility shall be at, or above, the maximum depreciation allowance specified by subpart 3.

C. The utility shall have made application to the appropriate regulatory agency for increased depreciation allowances, and the application shall not have been denied or rejected.

D. The utility must not have made any major capital expenditures within the last three years.

E. The utility must not have sold any long-term bonds or signed any long-term notes within the last three years.

If the utility has made major capital expenditures or entered into long-term debt obligations within the last three years, a satisfactory explanation of the rationale for these actions shall be made to the commissioner before an allowance for obsolescence will be granted.

The obsolescence allowances which may be applied to the utility's value will be calculated in the following manner:

(1) Method 1. A five-year average of the utility's annual throughput will be calculated. The throughput for the assessment year will be compared to this average and a percentage calculated. This percentage will be applied to the cost indicator of value calculated under subpart 3 in order to adjust the indicator for obsolescence. The adjusted cost indicator of value will be used in the calculation of the unit value under subpart 5. The following is an example of this procedure:

Year	Throughput in Barrels
1979	1,200,000
1980	1,300,000
1981	1,150,000
1982	1,100,000
1983	1,050,000
	5,800,000 Total
	1,160,000 Average Throughput

1.	1984 Throughput	1,000,000 Barrels
2.	Percent of 1984 Throughput to Five-Year Average Throughput	86%
3.	Cost Indicator of Value	$6,300,000
4.	Cost Indicator Adjusted for Obsolescence	5,418,000

(2) Method 2. The book depreciation shown on the books and accounts of the utility will be compared to the depreciation allowed by subpart 3. If the book depreciation exceeds the maximum depreciation allowance, 50 percent of the excess depreciation will be used in the calculation of the cost indicator of value. An example of this calculation is as follows:

1.	Book Depreciation	$ 6,000,000
2.	Maximum Allowable Depreciation	5,000,000
3.	Excess Depreciation	1,000,000
4.	50% of Excess Depreciation	500,000
5.	Utility Plant	11,000,000
6.	Construction Work in Progress	50,000
7.	Total Plant	11,050,000
8.	Nondepreciable Plant (Land, CWIP)	1,050,000
9.	Depreciable Plant	10,000,000
10.	Depreciation (Maximum 50%)	5,000,000
11.	Obsolescence Allowance	500,000
12.	Cost Indicator of Value	5,550,000

(3) Method 3. The income indicator of value computed in accordance with subpart 4 will be calculated by capitalizing the utility's three-year weighted net operating earnings for a specific term of years rather than into perpetuity. The term of years to be used will be the number of years remaining until the expected expiration of the utility's source of supply for product (oil, gas), or the number of years remaining until the utility's major assets (pipeline, pump stations, storage tanks, and similar assets) are fully depreciated, whichever is greater. An example of this capitalization process is as follows:

		1982	1983	1984
1.	Net Operating Earnings	$1,320,000	$1,000,000	$800,000
2.	Weighting	25%	35%	40%
3.	Weighted Net Operating Earnings	$330,000	$350,000	$320,000
4.	Total Weighted Net Operating Earnings		$1,000,000	
5.	Terms of years until major assets are fully depreciated			8
6.	Capitalization rate pursuant to subpart 4			11.75%
7.	Capitalization rate converted to term of 8 years			19.9548%
8.	Capitalized Income/Income Indicator of Value			$5,011,325

The commissioner shall apply to the valuation process whichever of the three obsolescence methods is most appropriate in order to equitably recognize the effect of obsolescence on the utility's value.

Subp. 8. **Retirements.** Utility operating property may be retired from the utility system while still in place if certain criteria are met:

A. The property must be physically disconnected from the utility system. In the case of electrical plants, the disconnection or dismantling of wires, cables, connectors, or transformers would constitute physical disconnection. In the case of pipelines, the disconnection of pipes, valves, or fittings would be evidence of physical disconnection.

B. An affidavit of retirement should be filed by the utility with the commissioner at least 30 days prior to the assessment date. This affidavit shall indicate the facility being retired and the date it was taken out of service.

The utility should make every effort to inform the commissioner of pending major retirements. The commissioner in turn shall notify the county assessor of impending major retirements as soon as this information becomes available to the department.

Utility property which is retired in place shall continue to be taxed for ad valorem purposes. However, its market value shall not be determined on the basis of its value as utility operating property.

If a utility should choose to temporarily retire a facility pending the development of an alternate fuel, greater demand, increased source of supply, or another valid reason, the cost of this facility must be transferred to the appropriate regulatory agency's account entitled "Held for Future Use." Standby facilities will not be considered to be temporarily retired unless their costs are carried in this account. Temporarily retired utility facilities will be valued taking into account a number of factors including age of the facility, type of facility, amount of maintenance and additional costs needed to restore the facility to operational status, length of retirement, and earning potential of the facility. In no instance shall a temporarily retired facility be valued lower than if the facility were considered nonoperating utility property.

Statutory Authority: *MS s 270.06 cl (14); 270.11 subds 1,6; 273.33 subd 2; 273.37 subd 2; 273.38*

History: *7 SR 1797; 8 SR 2723; 10 SR 18; 11 SR 635*

8100.0400 ALLOCATION.

Subpart 1. **General.** After the unit value of the utility property has been estimated, the portion of value which is attributable to Minnesota must be determined. This process of dividing the unit value of a utility company among the states in which the utility operates is called allocation. Each of the factors in the allocation formula is assigned a weighted percentage to denote the relative importance assigned to that factor. The resulting sum of the weighted factors multiplied by the unit value yields the valuation of the utility property which will, after the adjustments described in part 8100.0500, be subject to ad valorem tax in the state of Minnesota.

The factors to be considered in making allocations of unit value to Minnesota for the utility companies and the weight assigned to each factor for each class are specified in this rule.

Subp. 2. **Electric companies.** The original cost of the utility property located in Minnesota divided by the total original cost of the property in all states of operation is weighted at 90 percent. Gross revenue derived from operations in Minnesota divided by gross operations revenue from all states is weighted at ten percent.

The following example illustrates this formula, assuming a unit value of $20,000,000.

1.	Minnesota Plant Cost	$115,000,000	
			x .90 = 50.49%
2.	System Plant Cost	$205,000,000	
3.	Minnesota Gross Revenue	40,000,000	
			x .10 = 3.8%
4.	System Gross Revenue	$105,000,000	
5.	Total Percentage Allocable to Minnesota		54.29%
6.	Unit Value of System Plant		$20,000,000
7.	Amount of Value Allocable to Minnesota		$10,858,000

If any modification has been made to the cost indicator under part 8100.0300, subpart 3 to reflect the average cost per kilowatt adjustment of a plant or plants located in Minnesota, an alternative computation of the Minnesota allocation shall be made without giving effect to the modification in respect of such plant or plants.

Subp. 3. **Gas distribution companies.** The allocation of value of gas distribution companies shall be made considering the same factors as are used to determine the allocation of value of electric companies. The weight given to the original cost factor will be 75 percent, and gross revenue shall be weighted 25 percent.

Subp. 4. **Pipeline companies.** In addition to the cost factor and the gross revenue factor, the factor of weighted pipeline miles shall be considered in allocating the value of pipeline companies. Weighted pipeline miles means the number of miles of pipeline multiplied by the diameter of the pipe, measured in inches. To illustrate, a pipeline six miles long has three miles of pipe with a diameter of ten inches and three miles of pipe with a diameter of 30 inches. The weighted pipeline miles is 120.

3 miles x 10" diameter	= 30
3 miles x 30" diameter	= 90
Weighted pipeline miles	= 120

The following example illustrates the allocation of value of property of a pipeline company and the weights given to each factor:

1.	Minnesota Plant Cost	$13,500,000	
			x .75 = 25.76%
2.	System Plant Cost	$39,300,000	
3.	Minnesota Gross Revenue	$ 2,980,000	
			x .05 = 1.60%
4.	System Gross Revenue	$ 9,300,000	
5.	Minnesota Weighted Pipeline Miles	$ 9,500	x .20 = 7.01%
6.	System Weighted Pipeline Miles	$ 27,100	
7.	Total Percentage Allocable to Minnesota		34.37%

Statutory Authority: *MS s 270.06*

8100.0500 ADJUSTMENTS FOR NON-FORMULA-ASSESSED OR EXEMPT PROPERTY.

Subpart 1. **Deduction for exempt or non-formula-assessed property.** After the Minnesota portion of the unit value of the utility company is determined, any property which is non-formula-assessed or which is exempt from ad valorem tax, will be deducted from the Minnesota portion of the unit value. Only that qualifying property located within the state of Minnesota may be excluded.

Subp. 2. **Valuation formula not applicable to certain utility property.** The following properties will be valued by the local or county assessor and, therefore, the formula provided herein for the valuation of utility property will not be applicable for such property:

A. land;

B. nonoperating property; and

C. rights-of-way.

Subp. 3. **Deduction for cost of land and rights of way; application to nonoperating property.** The Minnesota portion of the unit value will be reduced by the original cost of land and rights-of-way. In the case of nonoperating property, the deduction shall be original cost, less the rate of depreciation applicable in the valuation process pursuant to part 8100.0300.

Subp. 4. **Deduction for exempt property.** A deduction from the Minnesota portion of the unit value shall also be made for property, real or personal, which is exempt from ad valorem tax. For instance, pollution control equipment for which an exemption has been granted is exempt. A deduction from the Minnesota portion of the unit value shall be made at original cost, less the applicable rate of depreciation used in the valuation process under part 8100.0300. The value of personal property, such as office machinery and vehicles, which is not taxed, shall also be excluded from the Minnesota portion of the unit value. The deduction shall be at original cost less the applicable rate of depreciation utilized in the valuation process.

The following example illustrates how these items are deducted from the Minnesota portion of the unit value. deducted from the Minnesota portion of the unit value.

1.	Minnesota Portion of Unit Value		$5,000,000
2.	Excludable Items - Nondepreciable		
	a. Land Assessed Locally		3,000
	b. Land Rights		2,000
3.	Excludable Items-Depreciable		
	a. General Plant Items	$10,000	
	b. Pollution Control Equipment	10,000	
	c. Gross Depreciable Items	20,000	
	d. Depreciated at 25%	5,000	
	e. Net Depreciable Excludable Items		15,000
4.	Total Excludable Items		20,000
5.	Minnesota Apportionable Value		$4,980,000

If any modification has been made to the cost indicator under part 8100.0300, subpart 3 to reflect the average cost per kilowatt adjustment of a plant or plants located in Minnesota, an alternative computation of the Minnesota apportionable value shall be made without giving effect to the modification in respect of such plant or plants.

Subp. 5. **Burden of proof and responsibility of utility company.** The utility company shall have the burden of proof to establish that the value of any property

should be excluded from the Minnesota portion of the unit value. Accordingly, the utility company shall have the responsibility to submit, in the form required by the commissioner of revenue, such schedules of exempt or non-formula-assessed property as he may require.

Statutory Authority: *MS s 270.06*

8100.0600 APPORTIONMENT.

Subpart 1. **Apportionment to taxing district.** After the unit valuation of the utility company has been allocated to the state of Minnesota and has been adjusted under part 8100.0500, the determined amount shall be apportioned or distributed to the taxing districts in Minnesota in which the company operates. This apportionment will be made by the commissioner of revenue on the basis of information submitted by the utility companies in annual reports filed with the commissioner.

If any modification has been made to the cost indicator under part 8100.0300, subpart 3 to reflect the average cost per kilowatt adjustment of a plant or plants located in Minnesota, the apportionment to the taxing districts made under subpart 4 shall be based upon the Minnesota apportionable value alternatively computed in part 8100.0500, subpart 4 without giving effect to the modification in respect of such plant or plants.

Subp. 2. **Required information.** The following information must be submitted for each taxing district:

A. the market value of the company's operating property by classification, as reflected in the last assessment, including the cost of leased taxable property;

B. the original cost of the company's operating property by classification, including the cost of leased taxable property;

C. the original cost of any new additions since the last assessment, including work in progress on the assessment date;

D. the market value of any retirements made after the last assessment, as reflected in that assessment; and

E. the original cost of any retirements made after the last assessment.

Subp. 3. **Required information when new taxing district established.** Whenever a new taxing district is established, the information submitted by the utility companies for the taxing district must be submitted in the same form as enumerated in subpart 2, items A to E. If the utility, because of administrative difficulty, is forced to make estimates of values and costs for property within new taxing districts, these estimates must be approved by the commissioner.

Subp. 4. **Market value of the operating utility property.** The total market value of each company's operating utility property in Minnesota shall be divided by the greater of:

A. the last market value of the company's operating utility property in each taxing district, plus original cost of new construction, reduced by the last market value of property retired since the last assessment; or

B. the original cost of the company's operating utility property in each taxing district plus original cost of new construction reduced by the original cost of property retired since the last assessment multiplied by the percentage as specified below.

For the 1982 assessment year the original costs shall be multiplied by 77.5 percent.

For the 1983 assessment year the original costs shall be multiplied by 80 percent.

For the 1984 assessment year the original costs shall be multiplied by 82.5 percent.

For the 1985 assessment year the original costs shall be multiplied by 85 percent.

For the 1986 assessment year the original costs shall be multiplied by 87.5 percent.

For the 1987 assessment year the original costs shall be multiplied by 90 percent.

For the 1988 assessment year the original costs shall be multiplied by 92.5 percent.

For the 1989 assessment year the original costs shall be multiplied by 95 percent.

For the 1990 assessment year the original costs shall be multiplied by 97 percent.

For the 1991 assessment year the original costs shall be multiplied by 100 percent.

All computations made under alternative A or B shall be made without giving effect to any modification to reflect the average cost per kilowatt adjustment made under part 8100.0300, subpart 3.

For this purpose, the last market value and the last assessment shall mean the latest assessment immediately prior to the current assessment. The portion of unit value to be assigned to each taxing district will be the resulting percentage multiplied by the Minnesota portion of the unit value, as adjusted pursuant to this rule.

Subp. 5. **Additional computation.** After all other computations have been made under this part, there shall be added to the value of each district in which there is located a plant or plants qualifying for the average cost per kilowatt adjustment under part 8100.0300, subpart 3 a share of the difference between the Minnesota apportionable value computed under part 8100.0500 with the adjustment, and without the adjustment in respect to plants located in Minnesota, in proportion to the amount of the adjustment made with respect to the property located in each such district.

Statutory Authority: *MS s 270.06 cl (14)*