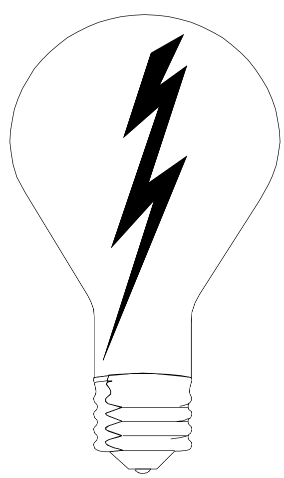
YEAR ENDING 2018

# ANNUAL REPORT

OF

Black Hills Power, Inc.

# ELECTRIC UTILITY



TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

# Electric Annual Report

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| Description | Schedule |
|---|---|


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# IDENTIFICATION

Year: 2018

| | | |
|---|---|---|
| 1. | Legal Name of Respondent: | Black Hills Power, Inc. |
| 2. | Name Under Which Respondent Does Business: | Black Hills Energy |
| 3. | Date Utility Service First Offered in Montana | 2/23/1968 |
| 4. | Address to send Correspondence Concerning Report: | PO Box 1400<br>Rapid City, SD 57709-1400 |
| 5. | Person Responsible for This Report: | Jason Keil<br>Manager Regulatory |
| 5a. | Telephone Number: | 605-721-1502 |
| Control Over Respondent | | |
| 1. | If direct control over the respondent was held by another entity at the end of year provide the following: | |
| | 1a. Name and address of the controlling organization or pe | Black Hills Corporation<br>7001 Mt. Rushmore Road<br>Rapid City, SD 57702 |
| | 1b. Means by which control was held: | Common Stock |
| | 1c. Percent Ownership: | 100% |

SCHEDULE 2

## Board of Directors

| Line No. | Name of Director and Address (City, State) (a) | | Remuneration (b) |
|---|---|---|---|
| 1 | David R. Emery | Rapid City, SD | $ 0 (a) |
| 2 | Linden R. Evans | Rapid City, SD | $ 0 (a) |
| 3 | Richard W. Kinzley | Rapid City, SD | $ 0 (a) |
| 4 | Brian G. Iverson | Rapid City, SD | $ 0 (a) |
| 5 | | | |
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| 8 | (a) As officers of the company, they receive no compensation for their services as directors | | |
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## Officers

Year: 2018

| Line No. | Title of Officer (a) | Department Supervised (b) | Name (c) |
|---|---|---|---|
| 1 | Chairman and Chief Executive Officer | | David R. Emery |
| 2 | President and Chief Operating Officer | | Linden R. Evans |
| 3 | Senior Vice President and Chief Financial Officer | | Richard W. Kinzley |
| 4 | Senior Vice President and General Counsel | | Brian G. Iverson |
| 5 | (also Chief Compliance Officer and Assistant Secretary) | | |
| 6 | Senior Vice President - Chief Information Officer | | Scott A. Buchholz |
| 7 | Senior Vice President - Chief Human Resources Officer | | Jennifer C. Landis |
| 8 | Vice President - Governance and Corporate Secretary | | Roxann R. Basham |
| 9 | Vice President - Corporate Controller and Treasurer (1) | | Kimberly F. Nooney |
| 10 | Vice President and Chief Risk Officer (2) | | Esther J. Newbrough |
| 11 | Vice President - Regulatory and Finance (4) | | Marne Jones |
| 12 | Assistant Corporate Secretary | | Amy K. Koenig |
| 13 | Vice President - Tax (5) | | Donna E. Genora |
| 14 | Group Vice President - Electric Utilities | | Stuart A. Wevik |
| 15 | Vice President - Regulatory Strategy | | Kyle D. White |
| 16 | Vice President - Facilities | | Perry S. Kush |
| 17 | Vice President - Growth and Strategy (6) | | Karen Beachy |
| 18 | Vice President - Energy Innovation (7) | | Mark L. Lux |
| 19 | Vice President - Power Delivery, Safety and Environmental (8) | | Marc Ostrem |
| 20 | Vice President - Customer Service | | Mark E. Stege |
| 21 | Vice President - Operations | | Nick Gardner |
| 22 | Vice President - Gas Asset Optimization | | Jodi Culp |
| 23 | | | |
| 24 | (1) Kimberly F. Nooney's title changed from Vice President - Treasurer to Vice President - Corporate | | |
| 25 | Controller and Treasurer effective June 6, 2018 | | |
| 26 | (2) Esther Newbrough's title changed from Vice President - Corporate Controller to Vice President and | | |
| 27 | Chief Risk Officer effective June 6, 2018 | | |
| 28 | (3) Jeffrey B. Berzina was removed as Vice President - Strategic Planning and Development effective | | |
| 29 | June 6, 2018 | | |
| 30 | (4) Marne M. Jones title changed from Vice President - Regulatory to Vice President - Regulatory and | | |
| 31 | Finance effective June 6, 2018 | | |
| 32 | (5) Donna E. Genora was appointed to replace Melinda Lee Watkins as Vice President - Tax effective | | |
| 33 | September 28, 2018 | | |
| 34 | (6) Karen Beachy's title changed from Vice President - Supply Chain to Vice President - Growth and | | |
| 35 | Strategy effective October 15, 2018 | | |
| 36 | (7) Mark Lux's title changed from Vice President - Power Generation, Safety and Environmental to Vice | | |
| 37 | President - Energy Innovation effective October 15, 2018 | | |
| 38 | (8) Marc Ostrem was appointed Vice President - Power Delivery, Safety and Environmental effective | | |
| 39 | October 15, 2018 | | |
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# CORPORATE STRUCTURE

Year: 2018

| | Subsidiary/Company Name | Line of Business | Earnings | Percent of Total |
|---|---|---|---|---|
| 1 | Black Hills Power, Inc. | Electric Utility | 45,644,951 | 100.00% |
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| 42 | | | | 100.00% |
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| 50 | **TOTAL** | | 45,644,951 | |

**Company Name: Black Hills Power d/b/a Black Hills Energy** **SCHEDULE 5**

# CORPORATE ALLOCATIONS

Year: 2018

| | Items Allocated | Classification | Allocation Method | $ to MT Utility | MT % | $ to Other |
|---|---|---|---|---|---|---|
| 1 | Not significant to Montana Operations | | | | | |
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| 34 | **TOTAL** | | | | | |

**Company Name: Black Hills Power d/b/a Black Hills Energy** **SCHEDULE 6**

## AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

Year: 2018

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Utility | (e) % Total Affil. Revs. | (f) Charges to MT Utility |
|---|---|---|---|---|---|---|
| 1 | Wyodak Resources Development Corp. | Coal Sales to Utility | Fair Market Value (based on similar arms-length | 12,869,441 | 18.92% | 747,715 |
| 2 | Cheyenne Light Fuel and Power | Non-Firm Energy Sales | Fair Market Value (based on similar arms-length | 500,712 | 0.30% | 29,091 |
| 3 | Black Hills Service Company | Information Technology, General Accounting, Insurance, Regulatory and Governmental Services, Facilities, Various Other Non-Power [illegible] | Black Hills Service Company Cost Allocation Manual | 29,973,409 | 44.57% | 1,741,455 |
| 4 | Black Hills Utility Holding Company | Various Non-power Goods and Services | Black Hills Utility Holdings Company Cost Allocation Manual | 17,150,853 | 42.33% | 996,465 |
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| 32 | **TOTAL** | | | 60,494,415 | | 3,514,726 |

# AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

Year: 2018

| Line No. | (a) Affiliate Name | (b) Products & Services | (c) Method to Determine Price | (d) Charges to Affiliate | (e) % Total Affil. Exp. | (f) Revenues to MT Utility |
|---|---|---|---|---|---|---|
| 1 | Wyodak Resources Development Corp. | Electricity | Wyoming Industrial Rate | 1,066,873 | 100.00% | |
| 2 | Black Hills Wyoming | Transmission Service | Point to Point open Access Transmission Tariff | 121,836 | 100.00% | |
| 3 | Cheyenne Light Fuel and Power | Transmission Service | Point to Point Open Access Transmission Tariff Fair Market Value | 4,042,548 | 4.49% | 234,872 |
| 4 | Black Hills Colorado Electric | Non-Firm Energy Sales | Fair Market Value (based on similar arms-length transactions | 321 | 0.00% | 19 |
| 5 | Cheyenne Light Fuel and Power | Non-Firm Energy Sales | Fair Market Value (based on similar arms-length transactions | 4,276,911 | 4.75% | 248,489 |
| 6 | Black Hills Colorado Electric | Generation Dispatch | Fair Market Value (based on similar arms-length transactions | 1,337,344 | 1.04% | 77,700 |
| 7 | Cheyenne Light Fuel and Power | Neil Simpson Complex | Fair Market Value (based on similar arms-length transactions | 8,234,027 | 9.15% | 478,397 |
| 8 | Cheyenne Light Fuel and Power | Environmental Complex | Fair Market Value (based on similar arms-length transactions | 78,804 | 0.09% | 4,579 |
| 9 | Cheyenne Light Fuel and Power | Generation Dispatch | Fair Market Value (based on similar arms-length transactions | 743,758 | 0.83% | 43,212 |
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| 31 | | | | | | |
| 32 | **TOTAL** | | | 19,902,422 | | 1,087,268 |

## MONTANA UTILITY INCOME STATEMENT

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | 400 Operating Revenues | 287,647,578 | 297,591,568 | 3.46% |
| 2 | | | | |
| 3 | Operating Expenses | | | |
| 4 | 401 Operation Expenses | 139,734,266 | 150,011,462 | 7.35% |
| 5 | 402 Maintenance Expense | 20,634,258 | 22,478,895 | 8.94% |
| 6 | 403 Depreciation Expense | 33,861,925 | 37,517,507 | 10.80% |
| 7 | 404-405 Amortization of Electric Plant | 1,902,824 | 2,055,830 | 8.04% |
| 8 | 406 Amort. of Plant Acquisition Adjustments | 97,406 | 97,406 | |
| 9 | 407 Amort. of Property Losses, Unrecovered Plant | | | |
| 10 | & Regulatory Study Costs | | | |
| 11 | 408.1 Taxes Other Than Income Taxes | 7,198,431 | 7,793,518 | 8.27% |
| 12 | 409.1 Income Taxes - Federal | 13,129,426 | 5,503,822 | -58.08% |
| 13 | - Other | | | |
| 14 | 410.1 Provision for Deferred Income Taxes | 26,116,270 | 18,078,261 | -30.78% |
| 15 | 411.1 (Less) Provision for Def. Inc. Taxes - Cr. | (25,142,697) | (12,180,983) | 51.55% |
| 16 | 411.4 Investment Tax Credit Adjustments | | | |
| 17 | 411.6 (Less) Gains from Disposition of Utility Plant | | | |
| 18 | 411.7 Losses from Disposition of Utility Plant | | | |
| 19 | | | | |
| 20 | **TOTAL Utility Operating Expenses** | 217,532,109 | 231,355,718 | 6.35% |
| 21 | **NET UTILITY OPERATING INCOME** | 70,115,469 | 66,235,850 | -5.53% |

## MONTANA REVENUES

SCHEDULE 9

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Sales of Electricity | | | |
| 2 | 440 Residential | 6,554 | 7,277 | 11.03% |
| 3 | 442 Commercial & Industrial - Small | 19,826 | 19,176 | -3.28% |
| 4 | Commercial & Industrial - Large | 8,016,279 | 8,149,045 | 1.66% |
| 5 | 444 Public Street & Highway Lighting | | | |
| 6 | 445 Other Sales to Public Authorities | | | |
| 7 | 446 Sales to Railroads & Railways | | | |
| 8 | 448 Interdepartmental Sales | | | |
| 9 | | | | |
| 10 | **TOTAL Sales to Ultimate Consumers** | 8,042,659 | 8,175,498 | 1.65% |
| 11 | 447 Sales for Resale | | | |
| 12 | | | | |
| 13 | **TOTAL Sales of Electricity** | 8,042,659 | 8,175,498 | 1.65% |
| 14 | 449.1 (Less) Provision for Rate Refunds | | 637,517 | |
| 15 | | | | |
| 16 | **TOTAL Revenue Net of Provision for Refunds** | 8,042,659 | 7,537,981 | -6.28% |
| 17 | Other Operating Revenues | | | |
| 18 | 450 Forfeited Discounts & Late Payment Revenues | 5,450 | 11 | -99.80% |
| 19 | 451 Miscellaneous Service Revenues | 38 | 8 | -78.95% |
| 20 | 453 Sales of Water & Water Power | | | |
| 21 | 454 Rent From Electric Property | | | |
| 22 | 455 Interdepartmental Rents | | | |
| 23 | 456 Other Electric Revenues | | | |
| 24 | | | | |
| 25 | **TOTAL Other Operating Revenues** | 5,488 | 19 | -99.65% |
| 26 | **Total Electric Operating Revenues** | 8,048,147 | 7,538,000 | -6.34% |

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Power Production Expenses | | | |
| 2 | | | | |
| 3 | Steam Power Generation | | | |
| 4 | Operation | | | |
| 5 | 500 Operation Supervision & Engineering | 485,136 | 843,984 | 73.97% |
| 6 | 501 Fuel | 18,959,100 | 20,474,508 | 7.99% |
| 7 | 502 Steam Expenses | 1,739,019 | 1,869,318 | 7.49% |
| 8 | 503 Steam from Other Sources | | | |
| 9 | 504 (Less) Steam Transferred - Cr. | | | |
| 10 | 505 Electric Expenses | 695,199 | 689,168 | -0.87% |
| 11 | 506 Miscellaneous Steam Power Expenses | 1,618,628 | 1,622,962 | 0.27% |
| 12 | 507 Rents | 2,291,413 | 2,524,112 | 10.16% |
| 13 | | | | |
| 14 | TOTAL Operation - Steam | 25,788,495 | 28,024,052 | 8.67% |
| 15 | | | | |
| 16 | Maintenance | | | |
| 17 | 510 Maintenance Supervision & Engineering | 1,829,833 | 2,641,141 | 44.34% |
| 18 | 511 Maintenance of Structures | 907,301 | 567,431 | -37.46% |
| 19 | 512 Maintenance of Boiler Plant | 5,595,150 | 5,039,160 | -9.94% |
| 20 | 513 Maintenance of Electric Plant | 1,703,066 | 1,028,103 | -39.63% |
| 21 | 514 Maintenance of Miscellaneous Steam Plant | 61,544 | 84,764 | 37.73% |
| 22 | | | | |
| 23 | TOTAL Maintenance - Steam | 10,096,894 | 9,360,599 | -7.29% |
| 24 | | | | |
| 25 | **TOTAL Steam Power Production Expenses** | 35,885,389 | 37,384,651 | 4.18% |
| 26 | | | | |
| 27 | Nuclear Power Generation | | | |
| 28 | Operation | | | |
| 29 | 517 Operation Supervision & Engineering | | | |
| 30 | 518 Nuclear Fuel Expense | | | |
| 31 | 519 Coolants & Water | | | |
| 32 | 520 Steam Expenses | | | |
| 33 | 521 Steam from Other Sources | | | |
| 34 | 522 (Less) Steam Transferred - Cr. | | | |
| 35 | 523 Electric Expenses | | | |
| 36 | 524 Miscellaneous Nuclear Power Expenses | | | |
| 37 | 525 Rents | | | |
| 38 | | | | |
| 39 | TOTAL Operation - Nuclear | | | |
| 40 | | | | |
| 41 | Maintenance | | | |
| 42 | 528 Maintenance Supervision & Engineering | | | |
| 43 | 529 Maintenance of Structures | | | |
| 44 | 530 Maintenance of Reactor Plant Equipment | | | |
| 45 | 531 Maintenance of Electric Plant | | | |
| 46 | 532 Maintenance of Miscellaneous Nuclear Plant | | | |
| 47 | | | | |
| 48 | TOTAL Maintenance - Nuclear | | | |
| 49 | | | | |
| 50 | **TOTAL Nuclear Power Production Expenses** | | | |

## MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Power Production Expenses -continued | | | |
| 2 | Hydraulic Power Generation | | | |
| 3 | Operation | | | |
| 4 | 535 Operation Supervision & Engineering | | | |
| 5 | 536 Water for Power | | | |
| 6 | 537 Hydraulic Expenses | | | |
| 7 | 538 Electric Expenses | | | |
| 8 | 539 Miscellaneous Hydraulic Power Gen. Expenses | | | |
| 9 | 540 Rents | | | |
| 10 | | | | |
| 11 | TOTAL Operation - Hydraulic | | | |
| 12 | | | | |
| 13 | Maintenance | | | |
| 14 | 541 Maintenance Supervision & Engineering | | | |
| 15 | 542 Maintenance of Structures | | | |
| 16 | 543 Maint. of Reservoirs, Dams & Waterways | | | |
| 17 | 544 Maintenance of Electric Plant | | | |
| 18 | 545 Maintenance of Miscellaneous Hydro Plant | | | |
| 19 | | | | |
| 20 | TOTAL Maintenance - Hydraulic | | | |
| 21 | | | | |
| 22 | **TOTAL Hydraulic Power Production Expenses** | | | |
| 23 | | | | |
| 24 | Other Power Generation | | | |
| 25 | Operation | | | |
| 26 | 546 Operation Supervision & Engineering | 1,144,395 | 1,226,499 | 7.17% |
| 27 | 547 Fuel | 3,742,585 | 4,658,536 | 24.47% |
| 28 | 548 Generation Expenses | 166,610 | 82,667 | -50.38% |
| 29 | 549 Miscellaneous Other Power Gen. Expenses | 367,047 | 387,281 | 5.51% |
| 30 | 550 Rents | 272,819 | 275,377 | 0.94% |
| 31 | | | | |
| 32 | TOTAL Operation - Other | 5,693,456 | 6,630,360 | 16.46% |
| 33 | | | | |
| 34 | Maintenance | | | |
| 35 | 551 Maintenance Supervision & Engineering | 135,069 | 69,046 | -48.88% |
| 36 | 552 Maintenance of Structures | 52,405 | 82,270 | 56.99% |
| 37 | 553 Maintenance of Generating & Electric Plant | 2,158,532 | 2,016,622 | -6.57% |
| 38 | 554 Maintenance of Misc. Other Power Gen. Plant | 143,762 | 118,572 | -17.52% |
| 39 | | | | |
| 40 | TOTAL Maintenance - Other | 2,489,768 | 2,286,510 | -8.16% |
| 41 | | | | |
| 42 | **TOTAL Other Power Production Expenses** | 8,183,224 | 8,916,870 | 8.97% |
| 43 | | | | |
| 44 | Other Power Supply Expenses | | | |
| 45 | 555 Purchased Power | 45,221,703 | 47,177,200 | 4.32% |
| 46 | 556 System Control & Load Dispatching | 1,871,993 | 1,528,605 | -18.34% |
| 47 | 557 Other Expenses | (106) | 110 | 203.77% |
| 48 | | | | |
| 49 | TOTAL Other Power Supply Expenses | 47,093,590 | 48,705,915 | 3.42% |
| 50 | | | | |
| 51 | **TOTAL Power Production Expenses** | 91,162,203 | 95,007,436 | 4.22% |

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2018

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | Transmission Expenses | | | |
| 2 | Operation | | | | |
| 3 | 560 | Operation Supervision & Engineering | 1,039,687 | 1,117,549 | 7.49% |
| 4 | 561 | Load Dispatching | 3,092,752 | 2,820,026 | -8.82% |
| 5 | 562 | Station Expenses | 431,397 | 485,162 | 12.46% |
| 6 | 563 | Overhead Line Expenses | 90,607 | 129,797 | 43.25% |
| 7 | 564 | Underground Line Expenses | | | |
| 8 | 565 | Transmission of Electricity by Others | 21,664,406 | 22,605,598 | 4.34% |
| 9 | 566 | Miscellaneous Transmission Expenses | 526,340 | 1,230,868 | 133.85% |
| 10 | 567 | Rents | | | |
| 11 | | | | | |
| 12 | | TOTAL Operation - Transmission | 26,845,189 | 28,389,000 | 5.75% |
| 13 | Maintenance | | | 91 | |
| 14 | 568 | Maintenance Supervision & Engineering | 4,495 | 5,546 | 23.38% |
| 15 | 569 | Maintenance of Structures | | | |
| 16 | 570 | Maintenance of Station Equipment | 102,299 | 131,783 | 28.82% |
| 17 | 571 | Maintenance of Overhead Lines | 428,657 | 538,498 | 25.62% |
| 18 | 572 | Maintenance of Underground Lines | | 2,176 | #DIV/0! |
| 19 | 573 | Maintenance of Misc. Transmission Plant | 36 | 1,048 | 2811.11% |
| 20 | | | | | |
| 21 | | TOTAL Maintenance - Transmission | 535,487 | 679,142 | 26.83% |
| 22 | | | | | |
| 23 | | **TOTAL Transmission Expenses** | 27,380,676 | 29,068,142 | 6.16% |
| 24 | | | | | |
| 25 | | Distribution Expenses | | | |
| 26 | Operation | | | | |
| 27 | 580 | Operation Supervision & Engineering | 1,274,990 | 1,757,662 | 37.86% |
| 28 | 581 | Load Dispatching | 389,612 | 468,704 | 20.30% |
| 29 | 582 | Station Expenses | 667,155 | 473,273 | -29.06% |
| 30 | 583 | Overhead Line Expenses | 528,737 | 436,235 | -17.49% |
| 31 | 584 | Underground Line Expenses | 378,209 | 352,860 | -6.70% |
| 32 | 585 | Street Lighting & Signal System Expenses | | 85,456 | #DIV/0! |
| 33 | 586 | Meter Expenses | 827,565 | 699,831 | -15.43% |
| 34 | 587 | Customer Installations Expenses | 490 | 287,261 | 58524.69% |
| 35 | 588 | Miscellaneous Distribution Expenses | 2,346,236 | 2,387,726 | 1.77% |
| 36 | 589 | Rents | 14,717 | 15,629 | 6.20% |
| 37 | | | | | |
| 38 | | TOTAL Operation - Distribution | 6,427,711 | 6,964,637 | 8.35% |
| 39 | Maintenance | | | | |
| 40 | 590 | Maintenance Supervision & Engineering | 7,837 | 26,297 | 235.55% |
| 41 | 591 | Maintenance of Structures | | | |
| 42 | 592 | Maintenance of Station Equipment | 131,515 | 115,204 | -12.40% |
| 43 | 593 | Maintenance of Overhead Lines | 5,262,798 | 7,476,893 | 42.07% |
| 44 | 594 | Maintenance of Underground Lines | 411,027 | 501,713 | 22.06% |
| 45 | 595 | Maintenance of Line Transformers | 60,142 | 87,702 | 45.82% |
| 46 | 596 | Maintenance of Street Lighting, Signal Systems | 154,126 | 67,061 | -56.49% |
| 47 | 597 | Maintenance of Meters | 66,019 | 70,705 | 7.10% |
| 48 | 598 | Maintenance of Miscellaneous Dist. Plant | 146,848 | 237,328 | 61.61% |
| 49 | | | | | |
| 50 | | TOTAL Maintenance - Distribution | 6,240,312 | 8,582,903 | 37.54% |
| 51 | | | | | |
| 52 | | **TOTAL Distribution Expenses** | 12,668,023 | 15,547,540 | 22.73% |

# MONTANA OPERATION & MAINTENANCE EXPENSES

Year: 2018

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | Customer Accounts Expenses | | | |
| 2 | Operation | | | | |
| 3 | 901 | Supervision | 88,969 | 86,288 | -3.01% |
| 4 | 902 | Meter Reading Expenses | 21,128 | 10,988 | -47.99% |
| 5 | 903 | Customer Records & Collection Expenses | 1,590,137 | 1,507,415 | -5.20% |
| 6 | 904 | Uncollectible Accounts Expenses | 577,515 | 516,082 | -10.64% |
| 7 | 905 | Miscellaneous Customer Accounts Expenses | 726,878 | 259,346 | -64.32% |
| 8 | | | | | |
| 9 | | TOTAL Customer Accounts Expenses | 3,004,627 | 2,380,119 | -20.78% |
| 10 | | | | | |
| 11 | | Customer Service & Information Expenses | | | |
| 12 | Operation | | | | |
| 13 | 907 | Supervision | 112,734 | 63,978 | -43.25% |
| 14 | 908 | Customer Assistance Expenses | 782,103 | 748,233 | -4.33% |
| 15 | 909 | Informational & Instructional Adv. Expenses | 39,859 | 25,730 | -35.45% |
| 16 | 910 | Miscellaneous Customer Service & Info. Exp. | 75,520 | 102,806 | 36.13% |
| 17 | | | | | |
| 18 | | TOTAL Customer Service & Info Expenses | 1,010,216 | 940,747 | -6.88% |
| 19 | | | | | |
| 20 | | Sales Expenses | | | |
| 21 | Operation | | | | |
| 22 | 911 | Supervision | | | |
| 23 | 912 | Demonstrating & Selling Expenses | 527 | 1,156 | 119.35% |
| 24 | 913 | Advertising Expenses | 2,097 | 15,139 | 621.94% |
| 25 | 916 | Miscellaneous Sales Expenses | 766 | 52 | -93.21% |
| 26 | | | | | |
| 27 | | TOTAL Sales Expenses | 3,390 | 16,347 | 382.21% |
| 28 | | | | | |
| 29 | | Administrative & General Expenses | | | |
| 30 | Operation | | | | |
| 31 | 920 | Administrative & General Salaries | 14,032,926 | 16,582,372 | 18.17% |
| 32 | 921 | Office Supplies & Expenses | 3,742,167 | 4,078,950 | 9.00% |
| 33 | 922 | (Less) Administrative Expenses Transferred - Cr. | (2,606,516) | (3,283,615) | -25.98% |
| 34 | 923 | Outside Services Employed | 3,201,947 | 3,985,847 | 24.48% |
| 35 | 924 | Property Insurance | 509,871 | 509,758 | -0.02% |
| 36 | 925 | Injuries & Damages | 1,404,169 | 1,399,457 | -0.34% |
| 37 | 926 | Employee Pensions & Benefits | 449,543 | 75,763 | -83.15% |
| 38 | 927 | Franchise Requirements | | | |
| 39 | 928 | Regulatory Commission Expenses | 1,029,565 | 839,823 | -18.43% |
| 40 | 929 | (Less) Duplicate Charges - Cr. | (184,613) | (256,178) | -38.76% |
| 41 | 930.1 | General Advertising Expenses | 345,628 | 304,742 | -11.83% |
| 42 | 930.2 | Miscellaneous General Expenses | 1,110,703 | 1,102,560 | -0.73% |
| 43 | 931 | Rents | 832,199 | 2,620,805 | 214.93% |
| 44 | | | | | |
| 45 | | TOTAL Operation - Admin. & General | 23,867,589 | 27,960,284 | 17.15% |
| 46 | Maintenance | | | | |
| 47 | 935 | Maintenance of General Plant | 1,271,800 | 1,569,742 | 23.43% |
| 48 | | | | | |
| 49 | | **TOTAL Administrative & General Expenses** | 25,139,389 | 29,530,026 | 17.47% |
| 50 | | | | | |
| 51 | | **TOTAL Operation & Maintenance Expenses** | 160,368,524 | 172,490,357 | 7.56% |

## MONTANA TAXES OTHER THAN INCOME

Year: 2018

| | Description of Tax | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | Payroll Taxes | | | |
| 2 | Superfund | | | |
| 3 | Secretary of State | | | |
| 4 | Montana Consumer Counsel | 7,052 | 3,799 | -46.13% |
| 5 | Montana PSC | 28,713 | 17,895 | -37.68% |
| 6 | Franchise Taxes | | | |
| 7 | Property Taxes | 455,809 | 430,602 | -5.53% |
| 8 | Tribal Taxes | | | |
| 9 | Montana Wholesale Energy Tax | 17,265 | 17,207 | -0.34% |
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| 50 | | | | |
| 51 | **TOTAL MT Taxes Other Than Income** | 508,839 | 469,503 | -7.73% |

## PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES

Year: 2018

| | Name of Recipient | Nature of Service | Total Company | Montana | % Montana |
|---|---|---|---|---|---|
| 1 | Amounts to Montana are not significant | | | | |
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| 49 | | | | | |
| 50 | **TOTAL Payments for Services** | | | | |

## POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS Year: 2018

| | Description | Total Company | Montana | % Montana |
|---|---|---|---|---|
| 1 | None | | | |
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| 49 | | | | |
| 50 | **TOTAL Contributions** | | | |

# Pension Costs

Year: 2018

| | | | | |
|---|---|---|---|---|
| 1 | Plan Name | | | |
| 2 | Defined Benefit Plan? Yes | Defined Contribution Plan? No | | |
| 3 | Actuarial Cost Method? Projected Unit Credit Method | IRS Code: 401b | | |
| 4 | Annual Contribution by Employer: 1,795,000 | Is the Plan Over Funded? No | | |
| 5 | | | | |
| | Item | Current Year | Last Year | % Change |
| 6 | **Change in Benefit Obligation** | | | |
| 7 | Benefit obligation at beginning of year | 67,561,782 | 64,973,455 | -3.83% |
| 8 | Service cost | 516,179 | 545,300 | 5.64% |
| 9 | Interest Cost | 2,194,498 | 2,340,497 | 6.65% |
| 10 | Plan participants' contributions | - | - | |
| 11 | Amendments | - | - | |
| 12 | Actuarial Gain | (2,878,653) | 4,007,686 | 239.22% |
| 13 | Acquisition | (1,912,539) | (860,408) | 55.01% |
| 14 | Benefits paid | (3,562,485) | (3,444,748) | 3.30% |
| 15 | Benefit obligation at end of year | 61,918,782 | 67,561,782 | 9.11% |
| 16 | **Change in Plan Assets** | | | |
| 17 | Fair value of plan assets at beginning of year | 59,883,968 | 53,888,256 | -10.01% |
| 18 | Actual return on plan assets | (1,884,387) | 6,150,214 | 426.38% |
| 19 | Acquisition | (1,568,406) | (709,754) | 54.75% |
| 20 | Employer contribution | 1,795,000 | 4,000,000 | 122.84% |
| 21 | Plan participants' contributions | - | - | |
| 22 | Benefits paid | (3,562,485) | (3,444,748) | 3.30% |
| 23 | Fair value of plan assets at end of year | 54,663,690 | 59,883,968 | 9.55% |
| 24 | **Funded Status** | (7,255,092) | (7,677,814) | -5.83% |
| 25 | Unrecognized net actuarial loss | 19,088,913 | 18,945,377 | -0.75% |
| 26 | Unrecognized prior service cost | 10,008 | 52,637 | 425.95% |
| 27 | Prepaid (accrued) benefit cost | 11,843,829 | 11,320,200 | -4.42% |
| 28 | | | | |
| 29 | **Weighted-average Assumptions as of Year End** | | | |
| 30 | Discount rate | 4.40% | 3.71% | -15.68% |
| 31 | Expected return on plan assets | 6.00% | 6.25% | 4.17% |
| 32 | Rate of compensation increase | 3.52% | 3.43% | -2.56% |
| 33 | | | | |
| 34 | **Components of Net Periodic Benefit Costs** | | | |
| 35 | Service cost | 516,179 | 545,300 | 5.64% |
| 36 | Interest cost | 2,194,498 | 2,340,497 | 6.65% |
| 37 | Expected return on plan assets | (3,545,334) | (3,589,752) | -1.25% |
| 38 | Amortization of prior service cost | 42,629 | 42,628 | 0.00% |
| 39 | Recognized net actuarial loss | 2,063,399 | 1,229,945 | -40.39% |
| 40 | Net periodic benefit cost | 1,271,371 | 568,618 | -55.28% |
| 41 | | | | |
| 42 | **Montana Intrastate Costs:** | | | |
| 43 | Pension Costs | | | |
| 44 | Pension Costs Capitalized | | | |
| 45 | Accumulated Pension Asset (Liability) at Year End | | | |
| 46 | **Number of Company Employees:** | | | |
| 47 | Covered by the Plan | 431 | 461 | 6.96% |
| 48 | Not Covered by the Plan | | | |
| 49 | Active | 144 | 176 | 22.22% |
| 50 | Retired | 221 | 220 | -0.45% |
| 51 | Deferred Vested Terminated | 66 | 65 | -1.52% |

# Other Post Employment Benefits (OPEBS)

Year: 2018

| | Item | Current Year | Last Year | % Change |
|---|---|---|---|---|
| 1 | **Regulatory Treatment:** | | | |
| 2 | Commission authorized - most recent | | | |
| 3 | Docket number: ___________ | | | |
| 4 | Order number: ___________ | | | |
| 5 | Amount recovered through rates | | | |
| 6 | **Weighted-average Assumptions as of Year End** | | | |
| 7 | Discount rate | 4.28% | 3.60% | -15.89% |
| 8 | Expected return on plan assets | | | |
| 9 | Medical Cost Inflation Rate | 4.94% | 5.00% | 1.21% |
| 10 | Actuarial Cost Method | | | |
| 11 | Rate of compensation increase | N/A | N/A | N/A |
| 12 | **List each method used to fund OPEBs (ie: VEBA, 401(h)) and if tax advantaged:** | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | **Describe any Changes to the Benefit Plan:** | | | |
| 16 | | | | |
| 17 | **TOTAL COMPANY** | | | |
| 18 | **Change in Benefit Obligation** | | | |
| 19 | Benefit obligation at beginning of year | 5,969,597.00 | 5,842,844.00 | -2.12% |
| 20 | Service cost | 193,017.00 | 206,063.00 | 6.76% |
| 21 | Interest Cost | 178,719.00 | 175,762.00 | -1.65% |
| 22 | Plan participants' contributions | 120,493.00 | 99,801.00 | -17.17% |
| 23 | Amendments | | - | |
| 24 | Actuarial Gain | (889,338.00) | 129,633.00 | 114.58% |
| 25 | Acquisition | (129,258.00) | (136,572.00) | -5.66% |
| 26 | Benefits paid | (388,403.00) | (347,934.00) | 10.42% |
| 27 | Benefit obligation at end of year | 5,054,827 | 5,969,597 | 18.10% |
| 28 | **Change in Plan Assets** | | | |
| 29 | Fair value of plan assets at beginning of year | - | - | |
| 30 | Actual return on plan assets | | | |
| 31 | Acquisition | | | |
| 32 | Employer contribution | 267,910.00 | 248,133.00 | -7.38% |
| 33 | Plan participants' contributions | 120,493.00 | 99,801.00 | -17.17% |
| 34 | Benefits paid | (388,403.00) | (347,934.00) | 10.42% |
| 35 | Fair value of plan assets at end of year | - | - | |
| 36 | **Funded Status** | (5,054,827.00) | (5,969,597.00) | -18.10% |
| 37 | Unrecognized net actuarial loss | (926,166.00) | 92,430.00 | 109.98% |
| 38 | Unrecognized prior service cost | (1,514,743.00) | (1,850,482.00) | -22.16% |
| 39 | Prepaid (accrued) benefit cost | (7,495,736) | (7,727,649) | -3.09% |
| 40 | **Components of Net Periodic Benefit Costs** | | | |
| 41 | Service cost | 193,017.00 | 206,063.00 | 6.76% |
| 42 | Interest cost | 178,719.00 | 175,762.00 | -1.65% |
| 43 | Expected return on plan assets | - | - | |
| 44 | Amortization of prior service cost | (335,739.00) | (335,739.00) | |
| 45 | Recognized net actuarial loss | | | |
| 46 | Net periodic benefit cost | 35,997 | 46,086 | 28.03% |
| 47 | **Accumulated Post Retirement Benefit Obligation** | | | |
| 48 | Amount Funded through VEBA | | | |
| 49 | Amount Funded through 401(h) | | | |
| 50 | Amount Funded through Other _______________ | | | |
| 51 | TOTAL | - | - | |
| 52 | Amount that was tax deductible - VEBA | | | |
| 53 | Amount that was tax deductible - 401(h) | | | |
| 54 | Amount that was tax deductible - Other ___________ | | | |
| 55 | TOTAL | - | - | |

# Other Post Employment Benefits (OPEBS) Continued

Year: 2018

| | Item | Current Year | Last Year | % Change |
|---|---|---|---|---|
| 1 | **Number of Company Employees:** | | | |
| 2 | Covered by the Plan | 324 | 343 | 5.86% |
| 3 | Not Covered by the Plan | | | |
| 4 | Active | 223 | 236 | 5.83% |
| 5 | Retired | 75 | 76 | 1.33% |
| 6 | Spouses/Dependents covered by the Plan | 68 | 63 | -7.35% |
| 7 | **Montana** | | | |
| 8 | **Change in Benefit Obligation** | | | |
| 9 | Benefit obligation at beginning of year | - | - | |
| 10 | Service cost | | | |
| 11 | Interest Cost | | | |
| 12 | Plan participants' contributions | | | |
| 13 | Amendments | | | |
| 14 | Actuarial Gain | | | |
| 15 | Acquisition | | | |
| 16 | Benefits paid | | | |
| 17 | Benefit obligation at end of year | - | - | |
| 18 | **Change in Plan Assets** | | | |
| 19 | Fair value of plan assets at beginning of year | - | - | |
| 20 | Actual return on plan assets | | | |
| 21 | Acquisition | | | |
| 22 | Employer contribution | | | |
| 23 | Plan participants' contributions | - | - | |
| 24 | Benefits paid | - | - | |
| 25 | Fair value of plan assets at end of year | - | - | |
| 26 | **Funded Status** | - | - | |
| 27 | Unrecognized net actuarial loss | | | |
| 28 | Unrecognized prior service cost | | | |
| 29 | Prepaid (accrued) benefit cost | - | - | |
| 30 | **Components of Net Periodic Benefit Costs** | | | |
| 31 | Service cost | - | - | |
| 32 | Interest cost | - | - | |
| 33 | Expected return on plan assets | - | - | |
| 34 | Amortization of prior service cost | | | |
| 35 | Recognized net actuarial loss | | | |
| 36 | Net periodic benefit cost | - | - | |
| 37 | **Accumulated Post Retirement Benefit Obligation** | | | |
| 38 | Amount Funded through VEBA | | | |
| 39 | Amount Funded through 401(h) | | | |
| 40 | Amount Funded through other ___________________ | | | |
| 41 | TOTAL | - | - | |
| 42 | Amount that was tax deductible - VEBA | | | |
| 43 | Amount that was tax deductible - 401(h) | | | |
| 44 | Amount that was tax deductible - Other | | | |
| 45 | TOTAL | - | - | |
| 46 | **Montana Intrastate Costs:** | | | |
| 47 | Pension Costs | | | |
| 48 | Pension Costs Capitalized | | | |
| 49 | Accumulated Pension Asset (Liability) at Year End | | | |
| 50 | **Number of Montana Employees:** | | | |
| 51 | Covered by the Plan | | | |
| 52 | Not Covered by the Plan | | | |
| 53 | Active | | | |
| 54 | Retired | | | |
| 55 | Spouses/Dependents covered by the Plan | | | |

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 16

Year: 2018

# TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

| Line No. | Name/Title | Base Salary | Bonuses | Other | Total Compensation | Total Compensation Last Year | % Increase Total Compensation |
|---|---|---|---|---|---|---|---|
| 1 | N/A | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
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Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 17

Year: 2018

# COMPENSATION OF TOP 5 CORPORATE EMPLOYEES - SEC INFORMATION

| Line No. | Name/Title | Base Salary | Bonuses | Other | Total Compensation | Total Compensation Last Year | % Increase Total Compensation |
|---|---|---|---|---|---|---|---|
| 1 | David R. Emery<br>Chairman and Chief Executive Officer | | | | | | |
| 2 | Richard W. Kinzley<br>Sr. Vice President and Chief Financial Officer | | | | | | |
| 3 | Linden R. Evans<br>President and Chief Operating Officer | | | | | | |
| 4 | Brian G. Iverson<br>Sr. Vice President and General Counsel | | | | | | |
| 5 | Scott A. Buchholz<br>Sr. Vice President and Chief Information Officer | | | | | | |

*PLEASE REFER TO ATTACHED SCHEDULE 17A - THE SUMMARY COMPENSATION TABLE FROM THE BHC ANNUAL MEETING OF SHAREHOLDERS AND PROXY STATEMENT.

# SUMMARY COMPENSATION TABLE

The following table sets forth the total compensation paid or earned by each of our Named Executive Officers for the years ended December 31, 2018, 2017 and 2016. We have no employment agreements with our Named Executive Officers.

| Name and Principal Position | Year | Salary | Stock Awards(2) | Non-Equity Incentive Plan Compensation(3) | Changes in Pension Value and Nonqualified Deferred Compensation Earnings (4) | All Other Compensation(5) | Total |
|---|---|---|---|---|---|---|---|
| **David R. Emery(1)** | 2018 | $820,000 | $1,943,679 | $1,196,503 | $523,260 | $140,256 | $4,623,698 |
| **Executive Chairman (former Chairman and CEO)** | 2017 | $812,000 | $1,942,843 | $560,232 | $2,155,930 | $92,930 | $5,563,935 |
| | 2016 | $767,000 | $1,926,358 | $1,283,218 | $1,061,157 | $104,751 | $5,142,484 |
| **Richard W. Kinzley** | 2018 | $381,000 | $491,036 | $303,238 | $— | $195,249 | $1,370,523 |
| **Sr. Vice President and Chief Financial Officer** | 2017 | $378,000 | $465,256 | $141,983 | $36,599 | $250,572 | $1,272,410 |
| | 2016 | $357,500 | $514,297 | $362,027 | $23,493 | $174,154 | $1,431,471 |
| **Linden R. Evans(1)** | 2018 | $530,000 | $859,369 | $492,132 | $— | $306,330 | $2,187,831 |
| **President and Chief Executive Officer (former President and Chief Operating Officer)** | 2017 | $523,333 | $818,045 | $230,428 | $59,631 | $385,948 | $2,017,385 |
| | 2016 | $485,833 | $773,875 | $529,411 | $37,711 | $299,611 | $2,126,441 |
| **Brian G. Iverson** | 2018 | $350,000 | $383,678 | $255,351 | $— | $123,852 | $1,112,881 |
| **Sr. Vice President and General Counsel** | 2017 | $346,667 | $357,856 | $97,823 | $17,736 | $145,405 | $965,487 |
| | 2016 | $325,000 | $422,433 | $246,837 | $11,890 | $111,429 | $1,117,589 |
| **Scott A. Buchholz** | 2018 | $320,000 | $245,514 | $212,240 | $38,765 | $111,285 | $927,804 |
| **Sr. Vice President and Chief Information Officer** | 2017 | $317,500 | $235,193 | $99,376 | $366,235 | $133,407 | $1,151,711 |
| | 2016 | $302,500 | $370,033 | $228,137 | $366,662 | $112,969 | $1,380,301 |

(1) Mr. Emery retired as our Chairman and Chief Executive Officer, effective December 31, 2018. He continues his full-time employment with the Company as Executive Chairman of the Board. Mr. Evans was named President and Chief Executive Officer effective January 1, 2019. Previously, he was President and Chief Operating Officer.

(2) Stock Awards represent the grant date fair value related to restricted stock and performance shares that have been granted as a component of long-term incentive compensation and for 2016, include special achievement awards associated with the acquisition of SourceGas. The grant date fair value is computed in accordance with the provisions of accounting standards for stock compensation. Assumptions used in the calculation of these amounts are included in Note 12 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018.

(3) Non-Equity Incentive Plan Compensation represents amounts earned under the Short-Term Incentive Plan. The Compensation Committee approved the payout of the 2018 awards on February 8, 2019 and the awards were paid on March 8, 2019.

(4) Change in Pension Value and Nonqualified Deferred Compensation Earnings represents the net positive increase in actuarial value of the Pension Plan, Pension Restoration Benefit ("PRB") and Pension Equalization Plans ("PEP") for the respective years. These benefits have been valued using the assumptions disclosed in Note 18 of the Notes to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2018. Because these assumptions sometimes change between measurement dates, the change in value reflects not only the change in value due to additional benefits earned during the period and the passage of time but also reflects the change in value caused by changes in the underlying actuarial assumptions. This has created significant volatility in the last three years with a large decrease in 2018 and a large increase in 2017 primarily related to the change in discount rates used to calculate the present value of these benefits. A value of zero is shown in the Summary Compensation Table for certain officers in 2018 because the SEC does not allow a negative number to be disclosed in the table.

# BALANCE SHEET

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | **Assets and Other Debits** | | | |
| 2 | Utility Plant | | | |
| 3 | 101 Electric Plant in Service | 1,174,339,782 | 1,292,737,577 | -9% |
| 4 | 101.1 Property Under Capital Leases | | | |
| 5 | 102 Electric Plant Purchased or Sold | | | |
| 6 | 104 Electric Plant Leased to Others | | | |
| 7 | 105 Electric Plant Held for Future Use | 1,266,452 | 1,266,452 | |
| 8 | 106 Completed Constr. Not Classified - Electric | 131,061,091 | 56,960,606 | 130% |
| 9 | 107 Construction Work in Progress - Electric | 4,832,298 | 29,903,691 | -84% |
| 10 | 108 (Less) Accumulated Depreciation | (403,933,945) | (429,383,242) | 6% |
| 11 | 111 (Less) Accumulated Amortization | | | |
| 12 | 114 Electric Plant Acquisition Adjustments | 4,870,308 | 4,870,308 | |
| 13 | 115 (Less) Accum. Amort. Elec. Acq. Adj. | (3,618,960) | (3,716,366) | 3% |
| 14 | 120 Nuclear Fuel (Net) | | | |
| 15 | **TOTAL Utility Plant** | 908,817,026 | 952,639,026 | -5% |
| 16 | | | | |
| 17 | **Other Property & Investments** | | | |
| 18 | 121 Nonutility Property | | | |
| 19 | 122 (Less) Accum. Depr. & Amort. for Nonutil. Prop. | | | |
| 20 | 123 Investments in Associated Companies | | | |
| 21 | 123.1 Investments in Subsidiary Companies | | 100,633 | -100% |
| 22 | 124 Other Investments | 4,926,313 | 4,787,904 | 3% |
| 23 | 125 Sinking Funds | | | |
| 24 | **TOTAL Other Property & Investments** | 4,926,313 | 4,888,537 | 1% |
| 25 | | | | |
| 26 | **Current & Accrued Assets** | | | |
| 27 | 131 Cash | 13,245 | 107,142 | -88% |
| 28 | 132-134 Special Deposits | | | |
| 29 | 135 Working Funds | 2,575 | 4,966 | -48% |
| 30 | 136 Temporary Cash Investments | | | |
| 31 | 141 Notes Receivable | | | |
| 32 | 142 Customer Accounts Receivable | 15,812,276 | 15,648,118 | 1% |
| 33 | 143 Other Accounts Receivable | 276,646 | 690,642 | -60% |
| 34 | 144 (Less) Accum. Provision for Uncollectible Accts. | (223,809) | (137,598) | -63% |
| 35 | 145 Notes Receivable - Associated Companies | | | |
| 36 | 146 Accounts Receivable - Associated Companies | 5,664,152 | 8,119,182 | -30% |
| 37 | 151 Fuel Stock | 2,660,435 | 2,311,193 | 15% |
| 38 | 152 Fuel Stock Expenses Undistributed | | | |
| 39 | 153 Residuals | | | |
| 40 | 154 Plant Materials and Operating Supplies | 19,102,008 | 20,891,945 | -9% |
| 41 | 155 Merchandise | | | |
| 42 | 156 Other Material & Supplies | | | |
| 43 | 157 Nuclear Materials Held for Sale | | | |
| 44 | 163 Stores Expense Undistributed | 1,598,604 | 1,246,859 | 28% |
| 45 | 165 Prepayments | 3,496,664 | 3,149,219 | 11% |
| 46 | 171 Interest & Dividends Receivable | | | |
| 47 | 172 Rents Receivable | | | |
| 48 | 173 Accrued Utility Revenues | 13,280,661 | 12,332,877 | 8% |
| 49 | 174 Miscellaneous Current & Accrued Assets | 82,392 | 403,215 | -80% |
| 50 | **TOTAL Current & Accrued Assets** | 61,765,849 | 64,767,760 | -5% |

# BALANCE SHEET

Year: 2018

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | **Assets and Other Debits (cont.)** | | | |
| 3 | | | | | |
| 4 | **Deferred Debits** | | | | |
| 5 | | | | | |
| 6 | 181 | Unamortized Debt Expense | 2,869,433 | 2,733,676 | 5% |
| 7 | 182.1 | Extraordinary Property Losses | | | |
| 8 | 182.2 | Unrecovered Plant & Regulatory Study Costs | | | |
| 8a | 182.3 | Other Regulatory Assets | 77,169,671 | 74,353,149 | |
| 9 | 183 | Prelim. Survey & Investigation Charges | 269,964 | 6,058,812 | -96% |
| 10 | 184 | Clearing Accounts | 1,132,859 | 1,286,527 | -12% |
| 11 | 185 | Temporary Facilities | | | |
| 12 | 186 | Miscellaneous Deferred Debits | 3,476,576 | 3,670,417 | -5% |
| 13 | 187 | Deferred Losses from Disposition of Util. Plant | | | |
| 14 | 188 | Research, Devel. & Demonstration Expend. | | | |
| 15 | 189 | Unamortized Loss on Reacquired Debt | 1,533,916 | 1,258,579 | 22% |
| 16 | 190 | Accumulated Deferred Income Taxes | 29,587,154 | 30,244,823 | -2% |
| 17 | | **TOTAL Deferred Debits** | 116,039,573 | 119,605,983 | -3% |
| 18 | | | | | |
| 19 | | **TOTAL Assets & Other Debits** | 1,091,548,761 | 1,141,901,306 | -4% |

| | Account Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 20 | | | | | |
| 21 | | **Liabilities and Other Credits** | | | |
| 22 | | | | | |
| 23 | **Proprietary Capital** | | | | |
| 24 | | | | | |
| 25 | 201 | Common Stock Issued | 23,416,396 | 23,416,396 | |
| 26 | 202 | Common Stock Subscribed | | | |
| 27 | 204 | Preferred Stock Issued | | | |
| 28 | 205 | Preferred Stock Subscribed | | | |
| 29 | 207 | Premium on Capital Stock | 42,076,811 | 42,076,811 | |
| 30 | 211 | Miscellaneous Paid-In Capital | | | |
| 31 | 213 | (Less) Discount on Capital Stock | | | |
| 32 | 214 | (Less) Capital Stock Expense | (2,501,882) | (2,501,882) | |
| 33 | 215 | Appropriated Retained Earnings | | | |
| 34 | 216 | Unappropriated Retained Earnings | 332,498,719 | 342,145,199 | -3% |
| 35 | 217 | (Less) Reacquired Capital Stock | (1,257,784) | (891,260) | -41% |
| 36 | | **TOTAL Proprietary Capital** | 394,232,260 | 404,245,264 | -2% |
| 37 | | | | | |
| 38 | **Long Term Debt** | | | | |
| 39 | | | | | |
| 40 | 221 | Bonds | 340,000,000 | 340,000,000 | |
| 41 | 222 | (Less) Reacquired Bonds | | | |
| 42 | 223 | Advances from Associated Companies | | | |
| 43 | 224 | Other Long Term Debt | 2,855,000 | 2,855,000 | |
| 44 | 225 | Unamortized Premium on Long Term Debt | | | |
| 45 | 226 | (Less) Unamort. Discount on L-Term Debt-Dr. | (90,390) | (86,250) | -5% |
| 46 | | **TOTAL Long Term Debt** | 342,764,610 | 342,768,750 | 0% |

# BALANCE SHEET

Year: 2018

| | Account Number & Title | | Last Year | This Year | % Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | **Total Liabilities and Other Credits (cont.)** | | | |
| 3 | | | | | |
| 4 | **Other Noncurrent Liabilities** | | | | |
| 5 | | | | | |
| 6 | 227 | Obligations Under Cap. Leases - Noncurrent | | | |
| 7 | 228.1 | Accumulated Provision for Property Insurance | | | |
| 8 | 228.2 | Accumulated Provision for Injuries & Damages | 470,194 | 394,497 | 19% |
| 9 | 228.3 | Accumulated Provision for Pensions & Benefits | 16,285,470 | 14,606,182 | 11% |
| 10 | 228.4 | Accumulated Misc. Operating Provisions | | | |
| 11 | 229 | Accumulated Provision for Rate Refunds | 841,743 | 2,523,526 | -67% |
| 12 | | **TOTAL Other Noncurrent Liabilities** | 17,597,407 | 17,524,205 | 0% |
| 13 | | | | | |
| 14 | **Current & Accrued Liabilities** | | | | |
| 15 | | | | | |
| 16 | 231 | Notes Payable | | | |
| 17 | 232 | Accounts Payable | 13,962,360 | 24,315,680 | -43% |
| 18 | 233 | Notes Payable to Associated Companies | 13,486,723 | 38,846,972 | -65% |
| 19 | 234 | Accounts Payable to Associated Companies | 25,653,259 | 25,803,650 | -1% |
| 20 | 235 | Customer Deposits | 1,393,629 | 1,874,819 | -26% |
| 21 | 236 | Taxes Accrued | 23,608,808 | 19,107,184 | 24% |
| 22 | 237 | Interest Accrued | 4,617,943 | 4,626,830 | 0% |
| 23 | 238 | Dividends Declared | | | |
| 24 | 239 | Matured Long Term Debt | | | |
| 25 | 240 | Matured Interest | | | |
| 26 | 241 | Tax Collections Payable | 1,023,878 | 1,029,258 | -1% |
| 27 | 242 | Miscellaneous Current & Accrued Liabilities | 5,112,681 | 5,563,791 | -8% |
| 28 | 243 | Obligations Under Capital Leases - Current | | | |
| 29 | | **TOTAL Current & Accrued Liabilities** | 88,859,281 | 121,168,184 | -27% |
| 30 | | | | | |
| 31 | **Deferred Credits** | | | | |
| 32 | | | | | |
| 33 | 252 | Customer Advances for Construction | 1,409,566 | 1,470,964 | -4% |
| 34 | 253 | Other Deferred Credits | 2,476,888 | 2,146,051 | 15% |
| 34a | 254 | Other Regulatory Liabilities | 103,957,605 | 108,327,594 | |
| 35 | 255 | Accumulated Deferred Investment Tax Credits | | | |
| 36 | 256 | Deferred Gains from Disposition Of Util. Plant | | | |
| 37 | 257 | Unamortized Gain on Reacquired Debt | | | |
| 38 | 281-283 | Accumulated Deferred Income Taxes | 140,251,144 | 144,250,295 | -3% |
| 39 | | **TOTAL Deferred Credits** | 248,095,203 | 256,194,904 | -3% |
| 40 | | | | | |
| 41 | **TOTAL LIABILITIES & OTHER CREDITS** | | 1,091,548,761 | 1,141,901,307 | -4% |

## MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | | | | |
| 2 | **Intangible Plant** | | | |
| 3 | | | | |
| 4 | 301 Organization | | | |
| 5 | 302 Franchises & Consents | | | |
| 6 | 303 Miscellaneous Intangible Plant | | | |
| 7 | | | | |
| 8 | **TOTAL Intangible Plant** | | | |
| 9 | | | | |
| 10 | **Production Plant** | | | |
| 11 | | | | |
| 12 | Steam Production | | | |
| 13 | | | | |
| 14 | 310 Land & Land Rights | | | |
| 15 | 311 Structures & Improvements | | | |
| 16 | 312 Boiler Plant Equipment | | | |
| 17 | 313 Engines & Engine Driven Generators | | | |
| 18 | 314 Turbogenerator Units | | | |
| 19 | 315 Accessory Electric Equipment | | | |
| 20 | 316 Miscellaneous Power Plant Equipment | | | |
| 21 | | | | |
| 22 | **TOTAL Steam Production Plant** | | | |
| 23 | | | | |
| 24 | Nuclear Production | | | |
| 25 | | | | |
| 26 | 320 Land & Land Rights | | | |
| 27 | 321 Structures & Improvements | | | |
| 28 | 322 Reactor Plant Equipment | | | |
| 29 | 323 Turbogenerator Units | | | |
| 30 | 324 Accessory Electric Equipment | | | |
| 31 | 325 Miscellaneous Power Plant Equipment | | | |
| 32 | | | | |
| 33 | **TOTAL Nuclear Production Plant** | | | |
| 34 | | | | |
| 35 | Hydraulic Production | | | |
| 36 | | | | |
| 37 | 330 Land & Land Rights | | | |
| 38 | 331 Structures & Improvements | | | |
| 39 | 332 Reservoirs, Dams & Waterways | | | |
| 40 | 333 Water Wheels, Turbines & Generators | | | |
| 41 | 334 Accessory Electric Equipment | | | |
| 42 | 335 Miscellaneous Power Plant Equipment | | | |
| 43 | 336 Roads, Railroads & Bridges | | | |
| 44 | | | | |
| 45 | **TOTAL Hydraulic Production Plant** | | | |

## MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Production Plant (cont.) | | | |
| 3 | | | | |
| 4 | Other Production | | | |
| 5 | | | | |
| 6 | 340 Land & Land Rights | | | |
| 7 | 341 Structures & Improvements | | | |
| 8 | 342 Fuel Holders, Producers & Accessories | | | |
| 9 | 343 Prime Movers | | | |
| 10 | 344 Generators | | | |
| 11 | 345 Accessory Electric Equipment | | | |
| 12 | 346 Miscellaneous Power Plant Equipment | | | |
| 13 | | | | |
| 14 | **TOTAL Other Production Plant** | | | |
| 15 | | | | |
| 16 | **TOTAL Production Plant** | | | |
| 17 | | | | |
| 18 | **Transmission Plant** | | | |
| 19 | | | | |
| 20 | 350 Land & Land Rights | | | |
| 21 | 352 Structures & Improvements | | | |
| 22 | 353 Station Equipment | | | |
| 23 | 354 Towers & Fixtures | | | |
| 24 | 355 Poles & Fixtures | | | |
| 25 | 356 Overhead Conductors & Devices | | | |
| 26 | 357 Underground Conduit | | | |
| 27 | 358 Underground Conductors & Devices | | | |
| 28 | 359 Roads & Trails | | | |
| 29 | | | | |
| 30 | **TOTAL Transmission Plant** | | | |
| 31 | | | | |
| 32 | **Distribution Plant** | | | |
| 33 | | | | |
| 34 | 360 Land & Land Rights | 26,304 | 26,304 | |
| 35 | 361 Structures & Improvements | (4,805) | (4,805) | |
| 36 | 362 Station Equipment | (442,870) | (433,639) | -2% |
| 37 | 363 Storage Battery Equipment | | | |
| 38 | 364 Poles, Towers & Fixtures | 439,151 | 450,185 | -2% |
| 39 | 365 Overhead Conductors & Devices | 481,679 | 485,273 | -1% |
| 40 | 366 Underground Conduit | 226 | 226 | |
| 41 | 367 Underground Conductors & Devices | 13,144 | 13,144 | |
| 42 | 368 Line Transformers | 91,169 | 89,584 | 2% |
| 43 | 369 Services | 8,109 | 8,109 | |
| 44 | 370 Meters | 856 | 856 | |
| 45 | 371 Installations on Customers' Premises | | | |
| 46 | 372 Leased Property on Customers' Premises | | | |
| 47 | 373 Street Lighting & Signal Systems | | | |
| 48 | | | | |
| 49 | **TOTAL Distribution Plant** | 612,963 | 635,237 | |

## MONTANA PLANT IN SERVICE (ASSIGNED & ALLOCATED)

Year: 2018

| | Account Number & Title | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | | | | |
| 2 | **General Plant** | | | |
| 3 | | | | |
| 4 | 389 Land & Land Rights | | | |
| 5 | 390 Structures & Improvements | | | |
| 6 | 391 Office Furniture & Equipment | | | |
| 7 | 392 Transportation Equipment | | | |
| 8 | 393 Stores Equipment | | | |
| 9 | 394 Tools, Shop & Garage Equipment | | | |
| 10 | 395 Laboratory Equipment | | | |
| 11 | 396 Power Operated Equipment | | | |
| 12 | 397 Communication Equipment | 425 | 425 | |
| 13 | 398 Miscellaneous Equipment | | | |
| 14 | 399 Other Tangible Property | | | |
| 15 | | | | |
| 16 | **TOTAL General Plant** | 425 | 425 | |
| 17 | | | | |
| 18 | **TOTAL Electric Plant in Service** | 613,388 | 635,662 | |

## MONTANA DEPRECIATION SUMMARY

Year: 2018

| | Functional Plant Classification | Plant Cost | Accumulated Depreciation Last Year Bal. | Accumulated Depreciation This Year Bal. | Current Avg. Rate |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | Steam Production | | | | |
| 3 | Nuclear Production | | | | |
| 4 | Hydraulic Production | | | | |
| 5 | Other Production | | | | |
| 6 | Transmission | | | | |
| 7 | Distribution | 635,236 | 970,781 | 986,851 | |
| 8 | General | 425 | 102 | 127 | |
| 9 | **TOTAL** | 635,661 | 970,883 | 986,978 | |

## MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED)

SCHEDULE 21

| | Account | | Last Year Bal. | This Year Bal. | %Change |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | 151 | Fuel Stock | N/A | N/A | |
| 3 | 152 | Fuel Stock Expenses Undistributed | | | |
| 4 | 153 | Residuals | | | |
| 5 | 154 | Plant Materials & Operating Supplies: | | | |
| 6 | | Assigned to Construction (Estimated) | | | |
| 7 | | Assigned to Operations & Maintenance | | | |
| 8 | | Production Plant (Estimated) | | | |
| 9 | | Transmission Plant (Estimated) | | | |
| 10 | | Distribution Plant (Estimated) | | | |
| 11 | | Assigned to Other | | | |
| 12 | 155 | Merchandise | | | |
| 13 | 156 | Other Materials & Supplies | | | |
| 14 | 157 | Nuclear Materials Held for Sale | | | |
| 15 | 163 | Stores Expense Undistributed | | | |
| 16 | | | | | |
| 17 | **TOTAL Materials & Supplies** | | | | |

## MONTANA REGULATORY CAPITAL STRUCTURE & COSTS

SCHEDULE 22

| | Commission Accepted - Most Recent | | % Cap. Str. | % Cost Rate | Weighted Cost |
|---|---|---|---|---|---|
| 1 | Docket Number | 83.4.25 | | | |
| 2 | Order Number | 4998 | | | |
| 3 | | | | | |
| 4 | Common Equity | | 52.83% | 15.00% | 7.92% |
| 5 | Preferred Stock | | 11.96% | 9.03% | 1.08% |
| 6 | Long Term Debt | | 35.21% | 7.75% | 2.73% |
| 7 | Other | | | | |
| 8 | **TOTAL** | | 100.00% | | 11.73% |
| 9 | | | | | |
| 10 | Actual at Year End | | | | |
| 11 | | | | | |
| 12 | Common Equity | | 54.11% | | |
| 13 | Preferred Stock | | | | |
| 14 | Long Term Debt | | 45.89% | | |
| 15 | Other | | | | |
| 16 | **TOTAL** | | 100.00% | | |

# STATEMENT OF CASH FLOWS

Year: 2018

| | Description | Last Year | This Year | % Change |
|---|---|---|---|---|
| 1 | | | | |
| 2 | Increase/(decrease) in Cash & Cash Equivalents: | | | |
| 3 | | | | |
| 4 | **Cash Flows from Operating Activities:** | | | |
| 5 | Net Income | 51,298,462 | 45,644,951 | 12% |
| 6 | Depreciation | 35,862,155 | 39,670,744 | -10% |
| 7 | Amortization | | | |
| 8 | Deferred Income Taxes - Net | 973,573 | 5,214,661 | -81% |
| 9 | Investment Tax Credit Adjustments - Net | | | |
| 10 | Change in Operating Receivables - Net | 4,342,206 | (2,360,277) | 284% |
| 11 | Change in Materials, Supplies & Inventories - Net | (1,054,123) | (1,409,773) | 25% |
| 12 | Change in Operating Payables & Accrued Liabilities - Net | (7,226,453) | (5,767,494) | -25% |
| 13 | Allowance for Funds Used During Construction (AFUDC) | (2,165,232) | (220,749) | -881% |
| 14 | Change in Other Assets & Liabilities - Net | 978,617 | (597,925) | 264% |
| 15 | Other Operating Activities (explained on attached page) | (2,606,755) | 4,524,627 | -158% |
| 16 | **Net Cash Provided by/(Used in) Operating Activities** | 80,402,450 | 84,698,765 | -5% |
| 17 | | | | |
| 18 | **Cash Inflows/Outflows From Investment Activities:** | | | |
| 19 | Construction/Acquisition of Property, Plant and Equipment | (80,703,026) | (74,021,987) | -9% |
| 20 | (net of AFUDC & Capital Lease Related Acquisitions) | | | |
| 21 | Acquisition of Other Noncurrent Assets | | (4,867,018) | 100% |
| 22 | Proceeds from Disposal of Noncurrent Assets | | 4,993,727 | -100% |
| 23 | Investments In and Advances to Affiliates | | | |
| 24 | Contributions and Advances from Affiliates | | | |
| 25 | Disposition of Investments in and Advances to Affiliates | | | |
| 26 | Other Investing Activities (explained on attached page) | 276,874 | - | |
| 27 | **Net Cash Provided by/(Used in) Investing Activities** | (80,426,152) | (73,895,278) | -9% |
| 28 | | | | |
| 29 | **Cash Flows from Financing Activities:** | | | |
| 30 | Proceeds from Issuance of: | | | |
| 31 | Long-Term Debt | | | |
| 32 | Preferred Stock | | | |
| 33 | Common Stock | | | |
| 34 | Other: | | | |
| 35 | Net Increase in Short-Term Debt | | | |
| 36 | Other: | (194,192) | | |
| 37 | Payment for Retirement of: | | | |
| 38 | Long-Term Debt | | | |
| 39 | Preferred Stock | | | |
| 40 | Common Stock | | | |
| 41 | Other: | | | |
| 42 | Net Decrease in Short-Term Debt | | | |
| 43 | Dividends on Preferred Stock | | | |
| 44 | Dividends on Common Stock | | | |
| 45 | Other Financing Activities (explained on attached page) | | (10,707,199) | 100% |
| 46 | **Net Cash Provided by (Used in) Financing Activities** | (194,192) | (10,707,199) | 98% |
| 47 | | | | |
| 48 | **Net Increase/(Decrease) in Cash and Cash Equivalents** | (217,894) | 96,288 | -326% |
| 49 | **Cash and Cash Equivalents at Beginning of Year** | 233,714 | 15,820 | 1377% |
| 50 | **Cash and Cash Equivalents at End of Year** | 15,820 | 112,108 | -86% |

**Attachment 23A**

**Footnotes for Statement of Cash Flow** **Year: 2018**

**Line 15, current year- Other Operating Activities consists of:**

| | | |
|---|---|---|
| $ | 516,982 | Bad debt expense |
| $ | 415,234 | Deferred financing costs |
| $ | 1,517,841 | Benefit plan expense |
| $ | (1,795,000) | Benefit plan contribution |
| $ | 3,296,355 | Change in regulatory assets and liabilities |
| $ | (921,894) | Other changes in current and non-current assets |
| $ | 1,480,510 | Other changes in current and non-current liabilities |
| $ | 64,332 | Other comprehensive income |
| $ | (49,733) | Gain on retirement of assets |
| $ | 4,524,627 | Total |

**Line 15, last year - Other Operating Activities consists of:**

| | | |
|---|---|---|
| $ | 578,212 | Bad debt expense |
| $ | 139,362 | Deferred financing costs |
| $ | 817,285 | Benefit plan expense |
| $ | (4,000,000) | Benefit plan contribution |
| $ | 71,025 | Changes in regulatory assets and liabilities |
| $ | (30,023) | Other changes in current and non-current assets |
| $ | (246,947) | Other changes in current and non-current liabilities |
| $ | 64,332 | Other comprehensive income |
| $ | (2,606,754) | Total |

**Line 26, last year-Other Investing Activities consist of:**

| | | |
|---|---|---|
| $ | 190,271 | Other investments |
| $ | 86,604 | Proceeds from sale of assets |
| $ | 276,875 | Total |

**Line 36, last year-Other Financing Activities consist of:**

| | | |
|---|---|---|
| $ | (194,192) | Borrowings from Money Pool |

**Line 45, current year-Other Financing Activities consist of:**

| | | |
|---|---|---|
| $ | (10,707,199) | Payments to Money Pool |

**Company Name: Black Hills Power d/b/a Black Hills Energy** SCHEDULE 24

# LONG TERM DEBT

Year: 2018

| | Description | Issue Date Mo./Yr. | Maturity Date Mo./Yr. | Principal Amount | Net Proceeds | Outstanding Per Balance Sheet | Yield to Maturity | Annual Net Cost Inc. Prem/Disc. | Total Cost % |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Series AG | 10/14 | 10/44 | 85,000,000 | 84,283,201 | 85,000,000 | 4.43% | 3,765,500 | 4.43% |
| 2 | | | | | | | | | |
| 3 | Series AE | 08/02 | 08/32 | 75,000,000 | 74,117,836 | 75,000,000 | 7.23% | 5,422,500 | 7.23% |
| 4 | | | | | | | | | |
| 5 | Series AF | 10/09 | 11/39 | 180,000,000 | 177,846,727 | 180,000,000 | 6.125% | 11,025,000 | 6.13% |
| 6 | | | | | | | | | |
| 7 | 1994 A Environmental | | | | | | | | |
| 8 | Improvement Bonds | 06/94 | 06/24 | 2,855,000 | 2,785,057 | 2,855,000 | 1.59% | 45,411 | 1.59% |
| 9 | | | | | | | | | |
| 10 | Series Y | 6/15/88 | 6/15/18 | 6,000,000 | 6,000,000 | | n/a | 11,109 | |
| 11 | Series Z | 5/29/91 | 5/29/21 | 35,000,000 | 35,000,000 | | n/a | 84,828 | |
| 12 | Series AB | 9/1/99 | 9/1/24 | 45,000,000 | 45,000,000 | | n/a | 116,828 | |
| 13 | Series 2004 Campbell County | 10/1/04 | 10/1/24 | 12,200,000 | 12,200,000 | | n/a | 68,121 | |
| 14 | | | | | | | | | |
| 15 | | | | | | | | | |
| 16 | Line 7 | | | | | | | | |
| 17 | The Series 1994A bonds have a variable component that resets weekly. The rate reflected is the average | | | | | | | | |
| 18 | interest rate for the year ended December 31, 2017. | | | | | | | | |
| 19 | | | | | | | | | |
| 20 | Lines 10 thru 13 | | | | | | | | |
| 21 | Identified bonds have been paid off. However, FERC allows for unamortized deferred finance costs or loss on | | | | | | | | |
| 22 | reacquired debt costs to be amortized over the original life of the bond. Annual costs reflect actual costs | | | | | | | | |
| 23 | incurred as a percent of total principal outstanding for Black Hills Power. | | | | | | | | |
| 24 | | | | | | | | | |
| 25 | | | | | | | | | |
| 26 | | | | | | | | | |
| 27 | | | | | | | | | |
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| 29 | | | | | | | | | |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | **TOTAL** | | | 342,855,000 | 339,032,821 | 342,855,000 | | 20,258,411 | 5.91% |

Company Name:  Black Hills Power d/b/a Black Hills Energy

SCHEDULE 25

# PREFERRED STOCK

Year:  2018

| | Series | Issue Date Mo./Yr. | Shares Issued | Par Value | Call Price | Net Proceeds | Cost of Money | Principal Outstanding | Annual Cost | Embed. Cost % |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | N/A | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | | | | | | | | | | |
| 4 | | | | | | | | | | |
| 5 | | | | | | | | | | |
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| 29 | | | | | | | | | | |
| 30 | | | | | | | | | | |
| 31 | | | | | | | | | | |
| 32 | **TOTAL** | | | | | | | | | |

**Company Name: Black Hills Power d/b/a Black Hills Energy** **SCHEDULE 26**

# COMMON STOCK

Year: 2018

| | | Avg. Number of Shares Outstanding | Book Value Per Share | Earnings Per Share | Dividends Per Share | Retention Ratio | Market Price High | Market Price Low | Price/ Earnings Ratio |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | January | 23,416,396 | | | | | | | |
| 5 | | | | | | | | | |
| 6 | February | 23,416,396 | | | | | | | |
| 7 | | | | | | | | | |
| 8 | March | 23,416,396 | | | | | | | |
| 9 | | | | | | | | | |
| 10 | April | 23,416,396 | | | | | | | |
| 11 | | | | | | | | | |
| 12 | May | 23,416,396 | | | | | | | |
| 13 | | | | | | | | | |
| 14 | June | 23,416,396 | | | | | | | |
| 15 | | | | | | | | | |
| 16 | July | 23,416,396 | | | | | | | |
| 17 | | | | | | | | | |
| 18 | August | 23,416,396 | | | | | | | |
| 19 | | | | | | | | | |
| 20 | September | 23,416,396 | | | | | | | |
| 21 | | | | | | | | | |
| 22 | October | 23,416,396 | | | | | | | |
| 23 | | | | | | | | | |
| 24 | November | 23,416,396 | | | | | | | |
| 25 | | | | | | | | | |
| 26 | December | 23,416,396 | | | | | | | |
| 27 | | | | | | | | | |
| 28 | | | | | | | | | |
| 29 | | | | | | | | | |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | TOTAL Year End | | | | | | | | |

## MONTANA EARNED RATE OF RETURN

Year: 2018

| | Description | Last Year | This Year | % Change |
|---|---|---|---|---|
| | Rate Base | | | |
| 1 | | | | |
| 2 | 101 Plant in Service | | | |
| 3 | 108 (Less) Accumulated Depreciation | | | |
| 4 | **NET Plant in Service** | | | |
| 5 | | | | |
| 6 | Additions | | | |
| 7 | 154, 156 Materials & Supplies | | | |
| 8 | 165 Prepayments | | | |
| 9 | Other Additions | | | |
| 10 | **TOTAL Additions** | | | |
| 11 | | | | |
| 12 | Deductions | | | |
| 13 | 190 Accumulated Deferred Income Taxes | | | |
| 14 | 252 Customer Advances for Construction | | | |
| 15 | 255 Accumulated Def. Investment Tax Credits | | | |
| 16 | Other Deductions | | | |
| 17 | **TOTAL Deductions** | | | |
| 18 | **TOTAL Rate Base** | | | |
| 19 | | | | |
| 20 | **Net Earnings** | | | |
| 21 | | | | |
| 22 | **Rate of Return on Average Rate Base** | | | |
| 23 | | | | |
| 24 | **Rate of Return on Average Equity** | | | |
| 25 | | | | |
| 26 | Major Normalizing Adjustments & Commission | | | |
| 27 | Ratemaking adjustments to Utility Operations | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | Note: This schedule is not completed because | | | |
| 32 | Montana revenues represents less than | | | |
| 33 | 2.53% of the Company's revenue. | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | | | | |
| 37 | | | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | | | | |
| 42 | | | | |
| 43 | | | | |
| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | **Adjusted Rate of Return on Average Rate Base** | | | |
| 48 | | | | |
| 49 | **Adjusted Rate of Return on Average Equity** | | | |

## MONTANA COMPOSITE STATISTICS

Year: 2018

| | | Description | Amount |
|---|---|---|---|
| 1 | | | |
| 2 | | Plant (Intrastate Only) (000 Omitted) | |
| 3 | | | |
| 4 | 101 | Plant in Service | 636 |
| 5 | 107 | Construction Work in Progress | |
| 6 | 114 | Plant Acquisition Adjustments | |
| 7 | 105 | Plant Held for Future Use | |
| 8 | 154, 156 | Materials & Supplies | |
| 9 | | (Less): | |
| 10 | 108, 111 | Depreciation & Amortization Reserves | (987) |
| 11 | 252 | Contributions in Aid of Construction | |
| 12 | | | |
| 13 | | **NET BOOK COSTS** | (351) |
| 14 | | | |
| 15 | | Revenues & Expenses (000 Omitted) | |
| 16 | | | |
| 17 | 400 | Operating Revenues | 7,538 |
| 18 | | | |
| 19 | 403 - 407 | Depreciation & Amortization Expenses | |
| 20 | | Federal & State Income Taxes | |
| 21 | | Other Taxes | |
| 22 | | Other Operating Expenses | |
| 23 | | TOTAL Operating Expenses | |
| 24 | | | |
| 25 | | Net Operating Income | 7,538 |
| 26 | | | |
| 27 | 415-421.1 | Other Income | |
| 28 | 421.2-426.5 | Other Deductions | |
| 29 | | | |
| 30 | | **NET INCOME** | 7,538 |
| 31 | | | |
| 32 | | Customers (Intrastate Only) | |
| 33 | | | |
| 34 | | Year End Average: | |
| 35 | | Residential | 13 |
| 36 | | Commercial | 24 |
| 37 | | Industrial | 8 |
| 38 | | Other | |
| 39 | | | |
| 40 | | **TOTAL NUMBER OF CUSTOMERS** | 45 |
| 41 | | | |
| 42 | | Other Statistics (Intrastate Only) | |
| 43 | | | |
| 44 | | Average Annual Residential Use (Kwh)) | 105,000 |
| 45 | | Average Annual Residential Cost per (Kwh) (Cents) * | 7 |
| 46 | | * Avg annual cost = [(cost per Kwh x annual use) + ( mo. svc chrg x 12)]/annual use | |
| 47 | | Average Residential Monthly Bill | 606 |
| 48 | | Gross Plant per Customer | (7.80) |

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 29

## MONTANA CUSTOMER INFORMATION

Year: 2018

| | City/Town | Population (Include Rural) | Residential Customers | Commercial Customers | Industrial & Other Customers | Total Customers |
|---|---|---|---|---|---|---|
| 1 | Carter and Powder River Counties | 2,903 | 13 | 24 | 8 | 45 |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
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| 28 | | | | | | |
| 29 | | | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | **TOTAL Montana Customers** | 2,903 | 13 | 24 | 8 | 45 |

**Company Name: Black Hills Power d/b/a Black Hills Energy** **SCHEDULE 30**

## MONTANA EMPLOYEE COUNTS

Year: 2018

| | Department | Year Beginning | Year End | Average |
|---|---|---|---|---|
| 1 | N/A | | | |
| 2 | | | | |
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| 47 | | | | |
| 48 | | | | |
| 49 | | | | |
| 50 | **TOTAL Montana Employees** | | | |

Company Name: Black Hills Power d/b/a Black Hills Energy **SCHEDULE 31**

## MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED) Year: 2019

| | Project Description | Total Company | Total Montana |
|---|---|---|---|
| 1 | N/A | | |
| 2 | | | |
| 3 | | | |
| 4 | | | |
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| 45 | | | |
| 46 | | | |
| 47 | | | |
| 48 | | | |
| 49 | | | |
| 50 | **TOTAL** | | |

# TOTAL SYSTEM & MONTANA PEAK AND ENERGY

Year: 2018

**System**

| | | Peak Day of Month | Peak Hour | Peak Day Volumes Megawatts | Total Monthly Volumes Energy (Mwh) | Non-Requirements Sales For Resale (Mwh) |
|---|---|---|---|---|---|---|
| 1 | Jan. | 16 | 800 | 395 | 284,255 | 28,862 |
| 2 | Feb. | 21 | 700 | 388 | 270,490 | 34,551 |
| 3 | Mar. | 5 | 1,900 | 344 | 252,146 | 28,689 |
| 4 | Apr. | 3 | 900 | 340 | 279,046 | 42,812 |
| 5 | May | 31 | 1,700 | 345 | 280,407 | 63,256 |
| 6 | Jun. | 28 | 1,600 | 400 | 255,810 | 35,798 |
| 7 | Jul. | 10 | 1,700 | 437 | 301,679 | 58,168 |
| 8 | Aug. | 2 | 1,600 | 406 | 294,594 | 61,153 |
| 9 | Sep. | 12 | 1,700 | 340 | 256,328 | 52,820 |
| 10 | Oct. | 8 | 1,900 | 313 | 220,624 | 38,028 |
| 11 | Nov. | 9 | 800 | 331 | 285,580 | 30,875 |
| 12 | Dec. | 27 | 1,700 | 379 | 296,618 | 43,707 |
| 13 | **TOTAL** | | | | 3,277,577 | 518,719 |

**Montana**

| | | Peak Day of Month | Peak Hour | Peak Day Volumes Megawatts | Total Monthly Volumes Energy (Mwh) | Non-Requirements Sales For Resale (Mwh) |
|---|---|---|---|---|---|---|
| 14 | Jan. | | | | | |
| 15 | Feb. | *Peak information maintained on a total system basis only | | | | |
| 16 | Mar. | | | | | |
| 17 | Apr. | | | | | |
| 18 | May | | | | | |
| 19 | Jun. | | | | | |
| 20 | Jul. | | | | | |
| 21 | Aug. | | | | | |
| 22 | Sep. | | | | | |
| 23 | Oct. | | | | | |
| 24 | Nov. | | | | | |
| 25 | Dec. | | | | | |
| 26 | **TOTAL** | | | | | |

## TOTAL SYSTEM Sources & Disposition of Energy

SCHEDULE 33

| | Sources | Megawatthours | Disposition | Megawatthours |
|---|---|---|---|---|
| 1 | Generation (Net of Station Use) | | | |
| 2 | Steam | 1,598,957 | Sales to Ultimate Consumers | |
| 3 | Nuclear | | (Include Interdepartmental) | 1,737,622 |
| 4 | Hydro - Conventional | | | |
| 5 | Hydro - Pumped Storage | | Requirements Sales | |
| 6 | Other | 135,265 | for Resale | 98,670 |
| 7 | (Less) Energy for Pumping | | | |
| 8 | **NET Generation** | 1,734,222 | Non-Requirements Sales | |
| 9 | Purchases | 1,626,177 | for Resale | 1,331,189 |
| 10 | Power Exchanges | | | |
| 11 | Received | 6,048 | Energy Furnished | |
| 12 | Delivered | 88,870 | Without Charge | |
| 13 | **NET Exchanges** | (82,822) | | |
| 14 | Transmission Wheeling for Others | | Energy Used Within | |
| 15 | Received | 6,331,008 | Electric Utility | 203,203 |
| 16 | Delivered | 6,331,008 | | |
| 17 | **NET Transmission Wheeling** | - | Total Energy Losses | (93,107) |
| 18 | Transmission by Others Losses | | | |
| 19 | **TOTAL** | 3,277,577 | **TOTAL** | 3,277,577 |

## SOURCES OF ELECTRIC SUPPLY

Year: 2018

| | Type | Plant Name | Location | Annual Peak (MW) | Annual Energy (Mwh) |
|---|---|---|---|---|---|
| 1 | Thermal | Ben French | Rapid City, SD | 98 | 1,167 |
| 2 | | | | | |
| 3 | Thermal | Ben French | Rapid City, SD | 10 | (165) |
| 4 | | | | | |
| 5 | Thermal | Wyodak | Gillette, WY | 69 | 511,184 |
| 6 | | | | | |
| 7 | Thermal | Neil Simpson II | Gillette, WY | 84 | 643,824 |
| 8 | | | | | |
| 9 | Thermal | Lange | Rapid City, SD | 39 | 9,291 |
| 10 | | | | | |
| 11 | Thermal | Neil Simpson CT | Gillette, WY | 39 | 12,854 |
| 12 | | | | | |
| 13 | Thermal | Wygen III | Gillette, WY | 60 | 442,617 |
| 14 | | | | | |
| 15 | Combined Cycle | Cheyenne Prairie | Cheyenne, WY | 60 | 104,346 |
| 16 | | | | | |
| 17 | Purchase | See Schedule 32 | | | 1,626,177 |
| 18 | | | | | |
| 19 | Wheeling | See Schedule 32 | | | |
| 20 | | | | | |
| 21 | Total Interchange | See Schedule 32 | | | (93,107) |
| 22 | | | | | |
| 23 | | | | | |
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| 46 | | | | | |
| 47 | | | | | |
| 48 | | | | | |
| 49 | **Total** | | | 459 | 3258188 |

Company Name: Black Hills Power d/b/a Black Hills Energy

SCHEDULE 35

## MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS

Year: 2018

| | Program Description | Current Year Expenditures | Last Year Expenditures | % Change | Planned Savings (MW & MWH) | Achieved Savings (MW & MWH) | Difference (MW & MWH) |
|---|---|---|---|---|---|---|---|
| 1 | N/A | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
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| 30 | | | | | | | |
| 31 | | | | | | | |
| 32 | **TOTAL** | | | | | | |

Company Name: Schedule 35a

# Electric Universal System Benefits Programs

| | Program Description | Actual Current Year Expenditures | Contracted or Committed Current Year Expenditures | Total Current Year Expenditures | Expected savings (MW and MWh) | Most recent program evaluation |
|---|---|---|---|---|---|---|
| 1 | Local Conservation | | | | | |
| 2 | N/A | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | Market Transformation | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | Renewable Resources | | | | | |
| 16 | | | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | Research & Development | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | Low Income | | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | Large Customer Self Directed | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | Total | | | | | |
| 43 | Number of customers that received low income rate discounts | | | | | |
| 44 | Average monthly bill discount amount ($/mo) | | | | | |
| 45 | Average LIEAP-eligible household income | | | | | |
| 46 | Number of customers that received weatherization assistance | | | | | |
| 47 | Expected average annual bill savings from weatherization | | | | | |
| 48 | Number of residential audits performed | | | | | |

Company Name: Schedule 35b

## Montana Conservation & Demand Side Management Programs

| | Program Description | Actual Current Year Expenditures | Contracted or Committed Current Year Expenditures | Total Current Year Expenditures | Expected savings (MW and MWh) | Most recent program evaluation |
|---|---|---|---|---|---|---|
| 1 | Local Conservation | | | | | |
| 2 | N/A | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | Demand Response | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | Market Transformation | | | | | |
| 16 | | | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | Research & Development | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | Low Income | | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | Other | | | | | |
| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | | | | | | |
| 45 | | | | | | |
| 46 | Total | | | | | |

## MONTANA CONSUMPTION AND REVENUES

Year: 2018

| | Sales of Electricity | Operating Revenues Current Year | Operating Revenues Previous Year | MegaWatt Hours Sold Current Year | MegaWatt Hours Sold Previous Year | Avg. No. of Customers Current Year | Avg. No. of Customers Previous Year |
|---|---|---|---|---|---|---|---|
| 1 | Residential | $7,277 | $6,554 | 105 | 96 | 13 | 12 |
| 2 | Commercial - Small | $19,176 | $19,826 | 169 | 184 | 24 | 25 |
| 3 | Commercial - Large | | | | | | |
| 4 | Industrial - Small | | | | | | |
| 5 | Industrial - Large | $8,149,045 | $8,016,279 | 116,655 | 114,289 | 8 | 6 |
| 6 | Interruptible Industrial | | | | | | |
| 7 | Public Street & Highway Lighting | | | | | | |
| 8 | Other Sales to Public Authorities | | | | | | |
| 9 | Sales to Cooperatives | | | | | | |
| 10 | Sales to Other Utilities | | | | | | |
| 11 | Interdepartmental | | | | | | |
| 12 | | | | | | | |
| 13 | **TOTAL** | $8,175,498 | $8,042,659 | 116,929 | 114,569 | 45 | 43 |

**NOTES TO FINANCIAL STATEMENTS**
**December 31, 2018 and 2017**

## 1. BUSINESS DESCRIPTION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### Business Description

Black Hills Power, Inc., doing business as Black Hills Energy - South Dakota (the "Company", “we”, “us” or “our”) is a regulated electric utility serving customers in South Dakota, Wyoming and Montana. We are a wholly-owned subsidiary of Black Hills Corporation ("BHC" or "Parent"), a public registrant listed on the New York Stock Exchange.

### Basis of Presentation

The financial statements include the accounts of Black Hills Power, Inc. and also our ownership interests in the assets, liabilities and expenses of our jointly owned facilities (Note 3).

The financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). Additionally, these requirement differ from GAAP related to the presentation of certain items discussed below.

Financial Statement Presentation and Basis of Accounting

The financial statements are presented on the basis of the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and this report differs from GAAP. The significant differences consist of the following:

- The accumulated reserve for estimated removal costs is included in the accumulated provision for depreciation for FERC reporting. For GAAP reporting it is reported as a regulatory liability.
- Current and long-term debt is classified in the balance sheet as all long-term debt in accordance with regulatory treatment, while GAAP presentation reflects current and long-term debt separately.
- Accumulated deferred tax assets and liabilities are classified in the balance sheet as gross deferred debits and credits, respectively, while GAAP presentation reflects either a net deferred asset or liability.
- Uncertain tax positions related to temporary differences are classified in the Balance Sheets within the deferred tax accounts in accordance with regulatory treatment, as compared to other noncurrent liabilities for GAAP purposes. In addition, interest related to uncertain tax positions is recognized in interest expense in accordance with regulatory treatment, as compared to income tax expense for GAAP purposes.
- Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent deferred debits and credits, respectively.
- Certain commodity trading purchases and sales transactions are presented gross as expense and revenues for the FERC presentation; however, the net margin is reported as net sales for the GAAP presentation.
- Various revenues and expenses are presented as other income and income deductions for the FERC presentation and reported as operating income and expense for the GAAP presentation.
- Only the service cost component of net periodic pension and post-retirement benefit costs can be capitalized for GAAP reporting. However, all cost components of net periodic pension and post-retirement benefit costs are eligible for capitalization under FERC regulations.

### Use of Estimates and Basis of Presentation

The preparation of financial statements in conformity with FERC requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or additional information may result in revised estimates and actual results could differ materially from those estimates.

**Cash and Cash Equivalents**

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. For purposes of the cash flow statements, we consider all highly liquid investments with original maturities of three months or less at the time of purchase to be cash and cash equivalents. As of December 31, 2018 and 2017, we have no cash equivalents.

**Regulatory Accounting**

Our regulated electric operations are subject to regulation by various state and federal agencies. The accounting policies followed are generally subject to the Uniform System of Accounts of FERC. If rate recovery becomes unlikely or uncertain due to competition or regulatory action, these accounting standards may no longer apply which could require these net regulatory assets to be charged to current income or OCI. Our regulatory assets represent amounts for which we will recover the cost, but generally are not allowed a return, except as described below. In the event we determine that our regulated net assets no longer meet the criteria for accounting standards for regulated operations, the accounting impact to us could be an extraordinary non-cash charge to operations, which could be material.

We had the following regulatory assets and liabilities as follows as of December 31 (in thousands):

| | 2018 | 2017 |
|---|---|---|
| **Regulatory assets:** | | |
| Deferred taxes on AFUDC [(b)] | 5,020 | 5,095 |
| Employee benefit plans [(c)] | 19,748 | 19,465 |
| Deferred energy and fuel cost adjustments [(a)] | 20,334 | 19,602 |
| Deferred taxes on flow through accounting [(a)] | 8,749 | 7,579 |
| Decommissioning costs, net of amortization | 8,196 | 10,252 |
| Vegetation management, net of amortization | 10,366 | 12,669 |
| Other regulatory assets [(a)] | 1,940 | 2,508 |
| | 74,353 | 77,170 |
| **Regulatory liabilities:** | | |
| Employee benefit plans and related deferred taxes [(c)] | 7,518 | 6,808 |
| Excess deferred income taxes [(c)] | 100,276 | 97,101 |
| Other regulatory liabilities [(c)] | 534 | 49 |
| | 108,328 | 103,958 |

(a) Recovery of costs but we are not allowed a rate of return.
(b) In addition to recovery of costs, we are allowed a rate of return.
(c) In addition to recovery or repayment of costs, we are allowed a return on a portion of this amount or a reduction in rate base

Regulatory assets represent items we expect to recover from customers through probable future increases in rates.

Deferred Taxes on AFUDC - The equity component of AFUDC is considered a permanent difference for tax purposes with the tax benefit being flowed through to customers as prescribed or allowed by regulators. If, based on a regulator's action, it is probable the utility will recover the future increase in taxes payable represented by this flow-through treatment through a rate revenue increase, a regulatory asset is recognized. This regulatory asset itself is a temporary difference for which a deferred tax liability must be recognized. Accounting standards for income taxes specifically address AFUDC-equity, and require a gross-up of such amounts to reflect the revenue requirement associated with a rate-regulated environment.

Employee Benefit Plans - Employee benefit plans include the unrecognized prior service costs and net actuarial loss associated with our defined benefit pension plan and post-retirement benefit plans in regulatory assets rather than in accumulated other comprehensive income. In addition, this regulatory asset includes the income tax effect of the adjustment required under accounting for compensation-defined benefit plans to record the full pension and post-retirement benefit obligations. Such amounts have been grossed-up to reflect the revenue requirement associated with a rate regulated environment.

Deferred Energy and Fuel Cost Adjustments - Deferred energy and fuel cost adjustments represent the cost of electricity delivered to our customers that is either higher or lower than the current rates and will be recovered or refunded in future rates. Deferred energy and fuel cost adjustments are recorded and recovered or amortized as approved by the appropriate state commission. We file periodic quarterly, semi-annual and/or annual filings to recover these costs based on the respective cost mechanisms approved by the applicable state utility commissions.

Deferred Taxes on Flow-Through Accounting - Under flow-through accounting, the income tax effects of certain tax items are reflected in our cost of service for the customer in the year in which the tax benefits are realized and result in lower utility rates. A regulatory asset was established to reflect that future increases in income taxes payable will be recovered from customers as the temporary differences reverse. As a result of this regulatory treatment, we continue to record a tax benefit for costs considered currently deductible for tax purposes, but are capitalized for book purposes.

Decommissioning Costs - We received approval in 2014 for regulatory treatment on the remaining net book values and decommissioning costs of our decommissioned coal plants.

Vegetation Management Costs - We received approval in 2013 for regulatory treatment on vegetation management maintenance costs for our distribution system rights-of-way.

Regulatory liabilities represent items we expect to refund to customers through probable future decreases in rates.

Employee Benefit Plans - Employee benefit plans represent the cumulative excess of pension and retiree healthcare costs recovered in rates over pension expense recorded in accordance with accounting standards for compensation - retirement benefits. In addition, this regulatory liability includes the income tax effect of the adjustment required under accounting for compensation - defined benefit plans, to record the full pension and post-retirement benefit obligations. Such income tax effect has been grossed-up to account for the revenue requirement associated with a rate regulated environment.

Excess Deferred Income Taxes - The revaluation of our deferred tax assets and liabilities due to the passage of the TCJA is recorded as an excess deferred income tax to be refunded to customers primarily using the normalization principles as prescribed in the TCJA. See additional details in Note 6.

**Accounts Receivable and Allowance for Doubtful Accounts**

Accounts receivable consists of sales to residential, commercial, industrial, municipal and other customers all of which do not bear interest. These accounts receivable are stated at billed and unbilled amounts net of write-offs or payment received.

We maintain an allowance for doubtful accounts which reflects our best estimate of uncollectible trade receivables. We regularly review our trade receivable allowances by considering such factors as historical experience, credit worthiness, the age of the receivable balances and current economic conditions that may affect collectibility.

In specific cases where we are aware of a customer's inability or reluctance to pay, we record an allowance for doubtful accounts to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be affected. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of commodity prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible or the time allowed for dispute under the contract has expired.

Following is a summary of accounts receivable at December 31 (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Accounts receivable, trade | $ 16,339 | $ 15,994 |
| Unbilled revenue | 12,333 | 13,280 |
| Less Allowance for doubtful accounts | (138) | (224) |
| Accounts receivable, net | $ 28,534 | $ 29,050 |

Changes to allowance for doubtful accounts for the years ended December 31, were as follows (in thousands):

| Description | Balance at beginning of year | Additions charged to costs and expenses | Deductions charged to costs and expenses | Balance at end of year |
|---|---|---|---|---|
| | | (in thousands) | | |
| Allowance for doubtful accounts: | | | | |
| 2018 | $ 224 | $ 911 | $ (997) | $ 138 |
| 2017 | $ 157 | $ 882 | $ (815) | $ 224 |
| 2016 | $ 207 | $ 644 | $ (694) | $ 157 |

**Revenue Recognition**

Revenues are recognized in an amount that reflects the consideration we expect to receive in exchange for goods or services, when control of the promised goods or services is transferred to our customers. Our primary types of revenue contracts are:

- Regulated electric utility services tariffs - Our regulated operations, as defined by ASC 980, provide services to regulated customers under rates, charges, terms and conditions of service, and prices determined by the jurisdictional regulators designated for our service territories. Collectively, these rates, charges, terms and conditions are included in a tariff, which governs all aspects of the provision of our regulated services. Our regulated services primarily encompass single performance obligations material to the context of the contract for delivery of commodity electricity and electric transmission services. These service revenues are variable based on quantities delivered, influenced by seasonal business and weather patterns. Tariffs are only permitted to be changed through a rate-setting process involving the regulator-empowered statute to establish contractual rates between the utility and its customers. All of our regulated utility sales are subject to regulatory-approved tariffs.

- Power sales agreements - We have long-term wholesale power sales agreements with other load serving entities, including affiliates, for the sale of excess power from owned generating units. These agreements include a combination of “take or pay” arrangements, where the customer is obligated to pay for the energy regardless of whether it actually takes delivery, as well as "requirements only" arrangements, where the customer is only obligated to pay for the energy the customer needs. In addition to these long-term contracts, we also sell excess energy to other load-serving entities on a short-term basis as a member of the Western States Power Pool. The pricing for all of these arrangements is included in the executed contracts or confirmations, reflecting the standalone selling price, and is variable based on energy delivered.

The following table depicts the disaggregation of revenue, including intercompany revenue, from contracts with customers by customer type and timing of revenue recognition. Sales tax and other similar taxes are excluded from revenues.

| | Twelve Months Ended December 31, 2018 (in thousands) |
|---|---|
| Customer types: | |
| Retail | $ 197,184 |
| Wholesale | 33,687 |
| Market - off-system sales | 17,691 |
| Transmission/Other | 49,015 |
| Revenue from contracts with customers | 297,577 |
| Other revenues | 503 |
| Total revenues | $ 298,080 |
| | |
| Timing of revenue recognition: | |
| Services transferred over time | $ 297,577 |
| Revenue from contracts with customers | $ 297,577 |

The majority of the our revenue contracts are based on variable quantities delivered; any fixed consideration contracts with an expected duration of one year or more are immaterial to our revenues. Variable consideration constraints in the form of discounts, rebates, credits, price concessions, incentives, performance bonuses, penalties or other similar items are not material for our revenue contracts. We are the principal in our revenue contracts, as we have control over the services prior to those services being transferred to the customer.

**Revenue Not in Scope of ASC 606**

Other revenues included in the table above include revenue accounted for under separate accounting guidance, including lease revenue under ASC 840 and alternative revenue programs revenue under ASC 980.

**Significant Judgments and Estimates**

*TCJA revenue reserve*

The TCJA or "tax reform", signed into law on December 22, 2017, reduced the federal corporate income tax rate from 35% to 21% effective for tax years beginning after December 31, 2017. We have been collaborating with our regulators in the states in which we provide utility service to deliver to customers the benefits of a lower corporate federal income tax rate beginning in 2018 with the passage of the TCJA. We estimated and recorded a revenue reserve of approximately $10 million during the year ended December 31, 2018.

On September 4, 2018, the SDPUC approved a settlement agreement for South Dakota Electric allowing the Company to pass on the benefits of a lower corporate federal income tax rate to our South Dakota retail customers. As of December 31, 2018, approximately $7.6 million has been delivered to customers and approximately $2.5 million remains in reserve.

*Unbilled Revenue*

To the extent that deliveries have occurred but a bill has not been issued, the Company accrues an estimate of the revenue since the latest billing. This estimate is calculated based on several factors including billings through the last billing cycle in a month and prices in effect in our jurisdictions. Each month the estimated unbilled revenue amounts are trued-up and recorded in Accounts receivable, net on the accompanying Balance Sheets.

*Contract Balances*

The nature of our primary revenue contracts provides an unconditional right to consideration upon service delivery; therefore, no customer contract assets or liabilities exist. The unconditional right to consideration is represented by the balance in our Accounts Receivable and is further discussed above. We do not typically incur costs that would be capitalized, to obtain or fulfill a contract.

**Practical Expedients**

Our revenue contracts generally provide for performance obligations that are fulfilled and transfer control to customers over time, represent a series of distinct services that are substantially the same, involve the same pattern of transfer to the customer, and provide a right to consideration from our customers in an amount that corresponds directly with the value to the customer for the performance completed to date. Therefore, we recognize revenue in the amount to which we have a right to invoice.

We have revenue contract performance obligations with similar characteristics, and we reasonably expect that the financial statement impact of applying the new revenue recognition guidance to a portfolio of contracts would not differ materially from applying this guidance to the individual contracts or performance obligations within the portfolio. Therefore, we have elected the portfolio approach in applying the new revenue guidance.

**Materials, Supplies and Fuel**

Materials, supplies and fuel used for construction, operation and maintenance purposes are recorded using the weighted-average cost method.

**Deferred Financing Costs**

Deferred financing costs are amortized over the estimated useful life of the related debt. Deferred financing costs are presented on the balance sheet as an adjustment to the related debt liabilities.

**Property, Plant and Equipment**

Additions to property, plant and equipment are recorded at cost. Included in the cost of regulated construction projects is AFUDC, when applicable, which represents the approximate composite cost of borrowed funds and a return on equity used to finance a regulated utility project. We also capitalize interest, when applicable, on undeveloped leasehold costs. In addition, asset retirement costs associated with tangible long-lived regulated utility assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived regulated utility assets in the period incurred. The amounts capitalized are included in Property, plant and equipment on the accompanying Balance Sheets.

The cost of regulated utility property, plant and equipment retired, or otherwise disposed of in the ordinary course of business, less salvage plus retirement costs, is charged to accumulated depreciation. At the time of such retirement, the accumulated provision for depreciation is charged with the original cost of the property retired and also for the net cost of removal. Ordinary repairs and maintenance of property, except as allowed under rate regulations, are charged to operations as incurred.

Property, plant and equipment is tested for impairment when it is determined that the carrying value of the assets may not be recoverable. A loss is recognized in the current period if it becomes probable that part of a cost of a plant under construction or recently completed plant will be disallowed for recovery from customers and a reasonable estimate of the disallowance can be made. For investments in property, plant and equipment that are abandoned and not expected to go into service, incurred costs and related deferred tax amounts are compared to the discounted estimated future rate recovery, and a loss is recognized, if necessary.

Depreciation provisions for regulated electric property, plant and equipment are computed on a straight-line basis using an annual composite rate of 2.3% in 2018 and 2.1% in 2017.

**Derivatives and Hedging Activities**

The accounting standards for derivatives and hedging require that derivative instruments be recorded on the balance sheet as either an asset or liability measured at its fair value and changes in the derivative instruments be recognized in earnings unless specific hedge accounting criteria are met and designated accordingly, including the normal purchase and normal sales exception. Changes in the fair value for derivative instruments that do not meet this exception are recognized in the income statement as they occur.

From time to time we utilize risk management contracts including interest rate swaps to fix the interest on variable rate debt, or to lock in the Treasury yield component associated with anticipated issuance of senior notes. For swaps that settled in connection with the issuance of senior debt, the effective portion is deferred as a component in AOCI and recognized as interest expense over the life of the senior note. As of December 31, 2018, we have no outstanding interest rate swap agreements.

Revenues and expenses on contracts that qualify as derivatives may be elected to be accounted for under the normal purchases and normal sales exception and are recognized when the underlying physical transaction is completed under the accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable amount of time, and price is not tied to an unrelated underlying derivative. As part of our regulated electric operations, we enter into contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy in the retail and wholesale markets with the intent and ability to deliver or take delivery. If it was determined that a transaction designated as a normal purchase or normal sale no longer met the exception, the fair value of the related contract would be reflected as either an asset or liability, under the accounting standards for derivatives and hedging.

**Fair Value Measurements**

Assets and liabilities are classified and disclosed in one of the following fair value categories:

Level 1 - Unadjusted quoted prices available in active markets that are accessible at the measurement date for identical unrestricted assets or liabilities. This level primarily consists of financial instruments such as exchange-traded securities or listed derivatives.

Level 2 - Pricing inputs include quoted prices for identical or similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means.

Level 3 - Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs reflect management's best estimate of fair value using its own assumptions about the assumptions a market participant would use in pricing the asset or liability.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels. We record transfers, if necessary, between levels at the end of the reporting period for all of our financial instruments.

Transfers into Level 3, if any, occur when significant inputs used to value the derivative instruments become less observable such as a significant decrease in the frequency and volume in which the instrument is traded, negatively impacting the availability of observable pricing inputs. Transfers out of Level 3, if any, occur when the significant inputs become more observable such as the time between the valuation date and the delivery date of a transaction becomes shorter, positively impacting the availability of observable pricing inputs.

Additional information is included in Note 5.

**Income Taxes**

We file a federal income tax return with other members of the Parent's consolidated group. For financial statement purposes, federal income taxes are allocated to the individual companies based on amounts calculated on a separate return basis.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA makes broad and complex changes to the U.S. tax code, including, but not limited to reducing the U.S. federal corporate tax rate from 35% to 21%. The Company uses the asset and liability method in accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities as well as operating loss and tax credit carryforwards. Such temporary differences are the result of provisions in the income tax law that either require or permit certain items to be reported on the income tax return in a different period than they are reported in the financial statements. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017.

We use the deferral method of accounting for investment tax credits as allowed by our rate-regulated jurisdictions. Such a method results in the investment tax credit being amortized as a reduction to income tax expense over the estimated useful lives of the underlying property that gave rise to the credit.

We recognize interest income or interest expense and penalties related to income tax matters in Other interest expense on the Statements of Income.

We account for uncertainty in income taxes recognized in the financial statements in accordance with the accounting standards for income taxes. The unrecognized tax benefit is classified within deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheets. See Note 6 for additional information.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. If we determine that we will be unable to realize all or part of our deferred tax assets in the future, an adjustment to the deferred tax asset would be charged to income in the period such determination was made. Although we believe our assumptions, judgments and estimates are reasonable, changes in tax law or our interpretations of tax laws and the resolution of current and any future tax audits could significantly impact the amounts provided for income taxes in our financial statements.

## 2. PROPERTY PLANT AND EQUIPMENT

Property, plant and equipment at December 31 consisted of the following (dollars in thousands):

| | 2018 | 2018 Weighted Average Useful Life (in years) | 2017 | 2017 Weighted Average Useful Life (in years) |
|---|---|---|---|---|
| Electric plant: | | | | |
| Production | 593,259 | 46 | 591,874 | 46 |
| Transmission | 208,610 | 48 | 186,045 | 49 |
| Distribution | 394,475 | 45 | 375,214 | 46 |
| Plant acquisition adjustment [(a)] | 4,870 | 32 | 4,870 | 32 |
| General | 154,621 | 28 | 153,535 | 32 |
| Total plant-in-service | 1,355,835 | | 1,311,538 | |
| Construction work in progress | 29,904 | | 4,832 | |
| Total electric plant | 1,385,739 | | 1,316,370 | |
| Less accumulated depreciation and amortization | (433,100) | | (407,553) | |
| Electric plant net of accumulated depreciation and amortization | 952,639 | | 908,817 | |

(a) The plant acquisition adjustment is included in rate base and is being recovered with 12 years remaining.

**(3) JOINTLY OWNED FACILITIES**

Our financial statements include our share of several jointly-owned utility facilities as described below. Our share of the facilities' expenses are reflected in the appropriate categories of operating expenses in the Statements of Income (Loss). Each owner of the facility is responsible for financing its investment in the jointly-owned facilities.

- We own a 20% interest in the Wyodak Plant (the "Plant"), a coal-fired electric generating station located in Campbell County, Wyoming. PacifiCorp owns the remaining ownership percentage and is the operator of the Plant. We receive our proportionate share of the Plant's capacity and are committed to pay our share of its additions, replacements and operating and maintenance expenses.

- We own a 35% interest in, and are the operator of, the Converter Station Site and South Rapid City Interconnection (the transmission tie), an AC-DC-AC transmission tie. Basin Electric owns the remaining ownership percentage. The transmission tie provides an interconnection between the Western and Eastern transmission grids, which provides us with access to both the WECC region and the MAPP region. The total transfer capacity of the transmission tie is 400 MW, including 200 MW West to East and 200 MW from East to West. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

- We own a 52% interest in the Wygen III power plant. MDU and the City of Gillette each owns an undivided ownership interest in Wygen III and are obligated to make payments for costs associated with administrative services and a proportionate share of the costs of operating the plant for the life of the facility. We retain responsibility for plant operations.

- We own 55 MW of Cheyenne Prairie, a 95 MW gas-fired power generation facility located in Cheyenne, Wyoming. Wyoming Electric owns the remaining 40 MW. We are committed to pay our proportionate share of the additions, replacements and operating and maintenance expenses.

As of December 31, 2018, our interests in jointly-owned generating facilities and transmission systems were (in thousands):

| Interest in jointly-owned facilities | | Plant in Service | Construction Work in Progress | Accumulated Depreciation |
|---|---|---|---|---|
| Wyodak Plant | $ | 115,198 $ | 384 $ | 61,730 |
| Transmission Tie | $ | 20,855 $ | 1,860 $ | 6,667 |
| Wygen III | $ | 140,072 $ | 645 $ | 22,647 |
| Cheyenne Prairie | $ | 92,053 $ | 69 $ | 11,460 |

**(4) LONG-TERM DEBT**

Long-term debt outstanding at December 31 was as follows (in thousands):

| | Due Date | Interest Rate at December 31, 2018 | Balance Outstanding December 31, 2018 | Balance Outstanding December 31, 2017 |
|---|---|---|---|---|
| First Mortgage Bonds due 2032 | August 15, 2032 | 7.23%$ | 75,000 $ | 75,000 |
| First Mortgage Bonds due 2039 | November 1, 2039 | 6.13% | 180,000 | 180,000 |
| First Mortgage Bonds due 2044 | October 20, 2044 | 4.43% | 85,000 | 85,000 |
| Less unamortized debt discount | | | (86) | (90) |
| Series 94A Debt [(a)] | June 1, 2024 | 1.93% | 2,855 | 2,855 |
| Long-term Debt | | $ | 342,769 $ | 342,765 |

(a) Variable interest rate at December 31, 2017.

Net deferred financing costs of approximately $2.7 million and $2.9 million were recorded on the accompanying Balance Sheets in deferred debits at December 31, 2018 and 2017, respectively, and are being amortized over the term of the debt. Amortization of deferred financing costs of approximately $0.1 million for both of the years ended December 31, 2018 and 2017 are included in Interest expense on the accompanying Statements of Income.

Substantially all of our property is subject to the lien of the indenture securing our first mortgage bonds. First mortgage bonds may be issued in amounts limited by property, earnings and other provisions of the mortgage indentures. We were in compliance with our debt covenants at December 31, 2018.

Long-term Debt Maturities

Scheduled maturities of our outstanding long-term debt (excluding unamortized discounts and unamortized deferred financing costs) are as follows (in thousands):

| | | |
|---|---|---|
| 2019 | $ | — |
| 2020 | $ | — |
| 2021 | $ | — |
| 2022 | $ | — |
| 2023 | $ | — |
| Thereafter | $ | 342,855 |

## (5) FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of our financial instruments at December 31 were as follows (in thousands):

| | 2018 | | 2017 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| Cash [(a)] | $ 112 | $ 112 | $ 16 | $ 16 |
| Long-term debt [(b)] | $ 342,769 | $ 412,894 | $ 342,765 | $ 446,978 |

(a) The cash fair value approximates carrying value and therefore is classified as Level 1 in the fair value hierarchy. We believe that the market risk arising from cash in a bank account is minimal.

(b) Long-term debt is valued based on observable inputs available either directly or indirectly for similar liabilities in active markets and therefore is classified in Level 2 in the fair value hierarchy.

The following methods and assumptions were used to estimate the fair value of each class of our financial instruments.

**Long-Term Debt**

For additional information on our long-term debt, see Note 4.

## (6) INCOME TAXES

Income tax expense from continuing operations for the years ended December 31 was as follows (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Current: | | |
| Federal | $ 5,457 | $ 13,154 |
| Deferred: | | |
| Federal | 5,955 | 974 |
| Excess deferred tax amortization | (740) | — |
| | $ 5,215 | $ 974 |
| Total income tax expense | $ 10,672 | $ 14,128 |

The temporary differences, which gave rise to the net deferred tax liability, at December 31 were as follows (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Deferred tax assets: | | |
| Employee Benefits | $ 2,404 | $ 3,012 |
| Regulatory liabilities | 25,587 | 24,984 |
| Other | 2,254 | 1,591 |
| Total deferred tax assets | 30,245 | 29,587 |
| Deferred tax liabilities: | | |
| Accelerated depreciation and other plant related differences | (125,594) | (122,002) |
| Regulatory assets | (7,147) | (7,008) |
| Employee benefits | (2,719) | (2,595) |
| Deferred costs | (8,572) | (8,447) |
| Other | (218) | (199) |
| Total deferred tax liabilities | (144,250) | (140,251) |
| Net deferred tax assets (liabilities) | $ (114,005) | $ (110,664) |

The effective tax rate differs from the federal statutory rate for the years ended December 31, as follows:

| | 2018 | 2017 |
|---|---|---|
| Federal statutory rate | 21.0 % | 35.0 % |
| Amortization of excess deferred and investment tax credits | (1.3)% | (0.1)% |
| AFUDC Equity | 0.1 % | (1.0)% |
| Flow through adjustments [a] | (1.7)% | (1.8)% |
| Tax credits | — % | — % |
| Tax reform [b] | 2.5 % | (9.2)% |
| Other | (1.7)% | (1.3)% |
| | 18.9 % | 21.6 % |

(a) Flow-through adjustments related primarily to an accounting method change for tax purposes that allows us to take a current tax deduction for repair costs. We recorded a deferred income tax liability in recognition of the temporary difference created between book and tax treatment and we flowed the tax benefit through to tax expense.

(b) On December 22, 2017, the TCJA was signed into law reducing the federal corporate rate from 35% to 21%, effective January 1, 2018. The 2017 effective tax rate reduction reflects the revaluation of deferred income taxes required by the change. During the year ended December 31, 2018, we recorded approximately $0.9 million of additional tax expense associated with changes in the prior estimated impacts of TCJA related items.

The following table reconciles the total amounts of unrecognized tax benefits, without interest, included in deferred tax accounts in accordance with regulatory treatment on the accompanying Balance Sheet (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Unrecognized tax benefits at January 1 | $ 302 | $ 493 |
| Additions for prior year tax positions | — | 13 |
| Additions for current year tax positions | 2 | — |
| Reductions for prior year tax positions | (55) | (204) |
| Unrecognized tax benefits at December 31 | $ 249 | $ 302 |

The total amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate is not material to the financial results of the Company.

It is the Company's continuing practice to recognize interest and/or penalties related to income tax matters in Other interest expense. During the years ended December 31, 2018 and 2017, the interest expense recognized was not material to the financial results of the Company.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of any audits or the expiration of statutes of limitations on or before December 31, 2019.

**Tax Reform**

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the TCJA. The TCJA reduced the U.S. federal corporate tax rate from 35% to 21%. As such, the Company has remeasured the deferred income taxes at the 21% federal tax rate as of December 31, 2017. As a result of the revaluation at December 31, 2017, our net deferred tax liability was reduced by approximately $74.1 million. Of the $74.1 million reduction, approximately $6.0 million was recorded as a reduction to tax expense as a result of remeasuring deferred tax liabilities not included in ratemaking. Based on our estimate of the amount of excess deferred income taxes included in ratemaking that would be used to reduce future customer rates, we recorded an increase in regulatory liabilities of approximately $97.1 million. An additional $29.0 million in regulatory liabilities was required to reflect the future revenue reduction required to return $68.1 million of previously collected income taxes to customers. We also recorded a $29.0 million deferred tax asset related to the $68.1 million regulatory liability.

Additional adjustments were made to the 2017 amounts during 2018 to reflect 1) tax returns, as filed, including amended tax return filings; 2) reclassifications regarding assumed ratemaking treatment; and 3) changes in estimates based on published guidance regarding the TCJA.

The accounts that increased and (decreased) in the remeasurement of deferred income taxes are reflected below (in millions):

**Initial Remeasurement in 2017**

| | Accounts | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Jurisdiction | 190 | 190 Other | 236 | 254[(a)] | 254 Other | 282 | 283 | 411.1 |
| FERC | $ 4.5 | $ (4.3) | $ — | $ 15.5 | $ (0.8) | $ (12.9) | $ (2.4) | $ (0.9) |
| State | 24.5 | (24.8) | — | 81.6 | (4.4) | (68.5) | (14.2) | (5.1) |
| Total | $ 29.0 | $ (29.1) | $ — | $ 97.1 | $ (5.2) | $ (81.4) | $ (16.6) | $ (6.0) |

**2018 Adjustments**

| Jurisdiction | 190 | 190 Other | 236 | 254[(a)] | 254 Other | 282 | 283 | 411.1 |
|---|---|---|---|---|---|---|---|---|
| FERC | $ — | $ — | $ — | $ — | $ — | $ — | $ — | $ — |
| State | 0.7 | 0.6 | (6.1) | 3.2 | (0.6) | 4.0 | 1.3 | 0.5 |
| Total | $ 0.7 | $ 0.6 | $ (6.1) | $ 3.2 | $ (0.6) | $ 4.0 | $ 1.3 | $ 0.5 |

**Adjusted Remeasurement Total**

| Jurisdiction | 190 | 190 Other | 236 | 254[(a)] | 254 Other | 282 | 283 | 411.1 |
|---|---|---|---|---|---|---|---|---|
| FERC | $ 4.5 | $ (4.3) | $ — | $ 15.5 | $ (0.8) | $ (12.9) | $ (2.4) | $ (0.9) |
| State | 25.2 | (24.2) | (6.1) | 84.8 | (5.0) | (64.5) | (12.9) | (4.6) |
| Total | $ 29.7 | $ (28.5) | $ (6.1) | $ 100.3 | $ (5.8) | $ (77.4) | $ (15.3) | $ (5.5) |

(a) Regulatory liability for excess deferred taxes were recorded on a net basis against regulatory assets for deficient deferred taxes in account 254

The amount of excess deferred income taxes that is considered protected and unprotected as of December 31 is reflected below (in millions):

| Jurisdiction | 2018 | 2017 |
|---|---|---|
| *Protected* | | |
| FERC | $ 15.5 | $ 15.5 |
| State | 67.8 | 62.7 |
| Total protected | $ 83.3 | $ 78.2 |
| *Unprotected* | | |
| FERC | $ — | $ — |
| State | 17.0 | 18.9 |
| Total unprotected | $ 17.0 | $ 18.9 |
| Total | $ 100.3 | $ 97.1 |

In 2018, we received an order from the South Dakota Public Utilities Commission approving a settlement stipulation regarding how customer rates should be reduced for excess deferred income taxes. The settlement stipulation required (i) a refund of protected and non-protected plant asset related excess deferred income taxes pursuant to the average rate assumption method (“ARAM”) and (ii) a refund in 2019 of all non-protected excess deferred income taxes not related to plant assets. The 2018 reduction in the excess deferred income tax regulatory liability associated with ARAM was offset against account 411, the account to which the original remeasurement of deferred income taxes was recorded in December 2017. The balance of the adjustments to the regulatory liability for net excess deferred taxes recorded in 2018 all reflected changes in estimates, not amortizations.

The adjustments to the regulatory liability (account 254) for the year ended December 31, 2018, the estimated amortization period based on regulatory orders, and the accounts where the adjustments and amortization were reported are reflected below (in millions):

| | | Accounts | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Jurisdiction | December 31, 2018 | 190 | 236 | 254 Other | 282 | 283 | 411 Amort. | 409-411 | December 31, 2017 | Amortization Period |
| *Protected* | | | | | | | | | | |
| FERC | $ 15.5 | $ — | $ — | $ — | $ — | $ — | $ — | $ — | $ 15.5 | (a) |
| State | 67.8 | 9.8 | — | — | 4.0 | — | (0.7) | — | 62.7 | (a) |
| Total protected | $ 83.3 | $ 9.8 | $ — | $ — | $ 4.0 | $ — | $ (0.7) | $ — | $ 78.2 | |
| *Unprotected* | | | | | | | | | | |
| FERC | — | $ — | $ — | $ — | $ — | $ — | $ — | $ — | $ — | (b) |
| State | 17.0 | (8.5) | (6.1) | (0.6) | — | 1.3 | — | 1.2 | 18.9 | (b) |
| Total unprotected | $ 17.0 | $ (8.5) | $ (6.1) | $ (0.6) | $ — | $ 1.3 | $ — | $ 1.2 | $ 18.9 | |
| Total | $ 100.3 | $ 1.3 | $ (6.1) | $ (0.6) | $ 4.0 | $ 1.3 | $ (0.7) | $ 1.2 | $ 97.1 | |

(a) The weighted average amortization period was estimated at 45 years under ARAM.

(b) The weighted average amortization period was estimated at 45 years under ARAM for plant-related unprotected and 1 year for non-plant unprotected.

The FERC has not yet issued an order regarding how customer rates should be reduced for excess deferred income taxes.

**(7) COMPREHENSIVE INCOME**

We record deferred gains (losses) in AOCI related to interest rate swaps designated as cash flow hedges and the amortization of components of our defined benefit plans. Deferred gains (losses) related to our interest rate swaps are recognized in earnings as they are amortized.

The components of the reclassification adjustments for the period, net of tax, included in Other Comprehensive Income were as follows (in thousands):

| | Location on the Statement of Income | Amounts Reclassified from AOCI | |
| --- | --- | --- | --- |
| | | 2016 | 2015 |
| Gains and Losses on cash flow hedges: | | | |
| Interest rate swaps gain (loss) | Interest expense | 64 | 64 |
| Income tax | Income tax benefit (expense) | (13) | (22) |
| Total reclassification adjustments related to cash flow hedges, net of tax | | 51 | 42 |
| | | | |
| Amortization of defined benefit plans: | | | |
| Actuarial gain (loss) | Operations and maintenance | 103 | 86 |
| Income tax | Income tax benefit (expense) | (22) | (30) |
| Total reclassification adjustments related to defined benefit plans, net of tax | | 81 | 56 |

Derivatives designated as cash flow hedges relate to a treasury lock entered into in August 2002 to hedge $50 million of our First Mortgage Bonds due on August 15, 2032. The treasury lock cash-settled on August 8, 2002, the bond pricing date, and resulted in a $1.8 million loss. The treasury lock is treated as a cash flow hedge and the resulting loss is carried in Accumulated other comprehensive loss and is being amortized over the life of the related bonds.

Balances by classification included within Accumulated other comprehensive loss on the accompanying Balance Sheets were as follows (in thousands):

| | Interest Rate Swaps | Employee Benefit Plans | Total |
|---|---|---|---|
| As of December 31, 2017 | $ (551) | $ (707) | $ (1,258) |
| Other comprehensive income (loss) before reclassifications | — | 235 | 235 |
| Amounts reclassified from AOCI | 51 | 81 | 132 |
| As of December 31, 2018 | $ (500) | $ (391) | $ (891) |

| | Interest Rate Swaps | Employee Benefit Plans | Total |
|---|---|---|---|
| As of December 31, 2016 | $ (593) | $ (669) | $ (1,262) |
| Other comprehensive income (loss) before reclassifications | — | (94) | (94) |
| Amounts reclassified from AOCI | 42 | 56 | 98 |
| As of December 31, 2017 | $ (551) | $ (707) | $ (1,258) |

## (8) EMPLOYEE BENEFIT PLANS

**Defined Contribution Plans**

BHC sponsors a 401(k) retirement savings plan (the 401(k) Plan). Participants in the 401(k) Plan may elect to invest a portion of their eligible compensation to the 401(k) Plan up to the maximum amounts established by the IRS. The 401(k) Plan provides employees the opportunity to invest up to 50% of their eligible compensation on a pre-tax or after-tax basis.

The 401(k) Plan provides a Company matching contribution for all eligible participants. Certain eligible participants who are not currently accruing a benefit in the Pension Plan also receive a Company retirement contribution based on the participant's age and years of service. Vesting of all Company and matching contributions occurs at 20% per year with 100% vesting when the participant has 5 years of service with the Company.

**Defined Benefit Pension Plan (Pension Plan)**

We have a defined benefit pension plan ("Pension Plan") covering certain eligible employees. The benefits for the Pension Plan are based on years of service and calculations of average earnings during a specific time period prior to retirement. The Pension Plan has been closed to new employees and certain employees who did not meet age and service based criteria.

The Pension Plan assets are held in a Master Trust. Our Board of Directors has approved the Pension Plan's investment policy. The objective of the investment policy is to manage assets in such a way that will allow the eventual settlement of our obligations to the Pension Plan's beneficiaries. To meet this objective, our pension assets are managed by an outside adviser using a portfolio strategy that will provide liquidity to meet the Pension Plan's benefit payment obligations. The Pension Plan's assets consist primarily of equity, fixed income and hedged investments.

The expected rate of return on the Pension Plan assets is determined by reviewing the historical and expected returns of both equity and fixed income markets, taking into account asset allocation, the correlation between asset class returns, and the mix of active and passive investments. The Pension Plan utilizes a dynamic asset allocation where the target allocation range to return-seeking and liability-hedging assets is determined based on the funded status of the Plan. As of December 31, 2018, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 29% to 37% return-seeking assets and 63% to 71% liability-hedging assets.

Our Pension Plan is funded in compliance with the federal government's funding requirements.

Pension Plan Assets

The percentages of total plan asset by investment category of our Pension Plan assets at December 31 were as follows:

| | 2018 | 2017 |
|---|---|---|
| Equity securities | 17% | 26% |
| Real estate | 4% | 4% |
| Fixed income funds | 71% | 63% |
| Cash and cash equivalents | 3% | 1% |
| Hedge funds | 5% | 6% |
| Total | 100% | 100% |

**Supplemental Non-qualified Defined Benefit Plans**

We have various supplemental retirement plans for key executives of the Company. The plans are non-qualified defined benefit and defined contribution plans (Supplemental Plans). The Supplemental Plans are subject to various vesting schedules and are not funded by the Company.

Plan Assets

We do not fund our Supplemental Plans. We fund on a cash basis as benefits are paid.

**Non-pension Defined Benefit Postretirement Healthcare Plans**

BHC sponsors retiree healthcare plans (Healthcare Plans) for employees who meet certain age and service requirements at retirement. Healthcare Plan benefits are subject to premiums, deductibles, co-payment provisions and other limitations.
Pre-65 retirees receive their retiree medical benefits through the Black Hills self-insured retiree medical plans. Healthcare coverage for Medicare-eligible BHP retirees is provided through an individual market healthcare exchange.

Plan Assets

We fund our Healthcare Plans on a cash basis as benefits are paid.

**Plan Contributions**

Contributions to the Pension Plan are cash contributions made directly to the Master Trust. Healthcare benefits include company and participant paid premiums.

Contributions for the years ended December 31 were as follows (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Defined Contribution Plans | | |
| Company Retirement Contribution | $ 876 | $ 861 |
| Matching Contributions | $ 1,272 | $ 1,306 |
| | | |
| Defined Benefit Plans | | |
| Defined Benefit Pension Plan | $ 1,795 | $ 4,000 |
| Non-Pension Defined Benefit Postretirement Healthcare Plans | $ 388 | $ 348 |
| Supplemental Non-qualified Defined Benefit Plan | $ 238 | $ 246 |

While we do not have required contributions, we expect to make approximately $1.8 million in contributions to our Defined Benefit Pension Plan in 2019.

**Fair Value Measurements**

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect their placement within the fair value hierarchy levels.

The following tables set forth, by level within the fair value hierarchy, the assets that were accounted for at fair value on a recurring basis (in thousands):

| **Pension Plan** | **December 31, 2018** | | | | | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Investments Measured at Fair Value | NAV [(a)] | Total |
| AXA Equitable General Fixed Income | $ — | $ 261 | $ — | $ 261 | $ — | $ 261 |
| Common Collective Trust - Cash and Cash Equivalent | — | 1,388 | — | 1,388 | — | 1,388 |
| Common Collective Trust - Equity | — | 9,436 | — | 9,436 | — | 9,436 |
| Common Collective Trust - Fixed Income | — | 39,047 | — | 39,047 | — | 39,047 |
| Common Collective Trust - Real Estate | — | 9 | — | 9 | 1,896 | 1,905 |
| Hedge Funds | — | — | — | — | 2,627 | 2,627 |
| Total investments measured at fair value | $ — | $ 50,141 | $ — | $ 50,141 | $ 4,523 | $ 54,664 |

| **Pension Plan** | **December 31, 2017** | | | | | |
|---|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total Investments Measured at Fair Value | NAV [(a)] | Total Fair Value |
| AXA Equitable General Fixed Income | $ — | $ 184 | $ — | $ 184 | $ — | $ 184 |
| Common Collective Trust - Cash and Cash Equivalent | — | 314 | — | 314 | — | 314 |
| Common Collective Trust - Equity | — | 15,749 | — | 15,749 | — | 15,749 |
| Common Collective Trust - Fixed Income | — | 37,732 | — | 37,732 | — | 37,732 |
| Common Collective Trust - Real Estate | — | 249 | — | 249 | 2,258 | 2,507 |
| Hedge Funds | — | — | — | — | 3,398 | 3,398 |
| Total investments measured at fair value | $ — | $ 54,228 | $ — | $ 54,228 | $ 5,656 | $ 59,884 |

(a) Certain investments that are measured at fair value using Net Asset Value “NAV” per share (or its equivalent) for practical expedient have not been classified in the fair value hierarchy. The fair value amounts presented in these tables for these investments are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the reconciliation of changes in the plan’s benefit obligations and fair value of plan assets above.

*AXA Equitable General Fixed Income Fund*: This fund is a diversified portfolio, primarily composed of fixed income instruments. Assets are invested in long-term holdings, such as commercial, agricultural and residential mortgages, publicly traded and privately placed bonds and real estate as well as short-term bonds. Fair values of mortgage loans are measured by discounting future contractual cash flows to be received on the mortgage loans using interest rates of loans with similar characteristics. The discount rate is derived from taking the appropriate U.S. Treasury rate with a like term. The fair value of public fixed maturity securities are generally based on prices obtained from independent valuation service providers with reasonableness prices compared with directly observable market trades. The fair value of privately placed securities are determined using a discounted cash flow model. These models use observable inputs with a discount rate based upon the average of spread surveys collected from private market intermediaries and industry sector of the issuer. The Plan’s investments in the AXA Equitable General Fixed Income Fund are categorized as Level 2.

*Common Collective Trust Funds:* These funds are valued based upon the redemption price of units held by the Plan, which is based on the current fair value of the common collective trust funds’ underlying assets. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. The Plan's investments in common collective trust funds, with the exception of shares of the common collective trust-real estate are categorized as Level 2.

*Common Collective Trust-Real Estate Fund*: This fund is valued based on various factors of the underlying real estate properties, including market rent, market rent growth, occupancy levels, etc. As part of the trustee's valuation process, properties are externally appraised generally on an annual basis. The appraisals are conducted by reputable independent appraisal firms and signed by appraisers that are members of the Appraisal Institute, with professional designation of Member, Appraisal Institute. All external appraisals are performed in accordance with the Uniform Standards of Professional Appraisal Practices. We receive monthly statements from the trustee, along with the annual schedule of investments and rely on these reports for pricing the units of the fund. The funds without participant withdrawal limitations are categorized as Level 2.

The following investments are measured at NAV and are not classified in the fair value hierarchy, in accordance with accounting guidance.

*Common Collective Trust-Real Estate Fund*: This is the same fund as above except that certain of the funds' assets contain participant withdrawal policies with restrictions on redemption and are therefore not included in the fair value hierarchy.

*Hedge Funds:* These funds represent investments in other investment funds that seek a return utilizing a number of diverse investment strategies. The strategies, when combined aim to reduce volatility and risk while attempting to deliver positive returns under all market conditions. Amounts are reported on a one-month lag. The fair value of hedge funds is determined using net asset value per share based on the fair value of the hedge fund's underlying investments. 20% of the shares may be redeemed at the end of each month with a 10-day notice and full redemptions are available at the end of each quarter with 45-day notice, and is limited to a percentage of the total net assets value of the fund. The net asset values are based on the fair value of each fund's underlying investments. There are no unfunded commitments related to these hedge funds.

**Other Plan Information**

The following tables provide a reconciliation of the employee benefit plan obligations, fair value of assets and amounts recognized in the Balance Sheets, components of the net periodic expense and elements of AOCI:

Benefit Obligations

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plans | |
|---|---|---|---|---|---|---|
| As of December 31 (in thousands) | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 |
| Change in benefit obligation: | | | | | | |
| Projected benefit obligation at beginning of year | $ 67,562 | $ 64,973 | $ 3,418 | $ 3,404 | $ 5,970 | $ 5,843 |
| Service cost | 516 | 545 | — | — | 193 | 206 |
| Interest cost | 2,194 | 2,341 | 108 | 116 | 179 | 176 |
| Actuarial (gain) loss | (2,878) | 4,008 | (296) | 144 | (889) | 130 |
| Benefits paid | (3,562) | (3,445) | (238) | (246) | (389) | (348) |
| Plan participants transfer to affiliate | (1,913) | (860) | — | — | (129) | (137) |
| Plan participants' contributions | — | — | — | — | 120 | 100 |
| Projected benefit obligation at end of year | $ 61,919 | $ 67,562 | $ 2,992 | $ 3,418 | $ 5,055 | $ 5,970 |

Employee Benefit Plan Assets

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plans | |
|---|---|---|---|---|---|---|
| As of December 31 (in thousands) | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 |
| Beginning fair value of plan assets | $ 59,884 | $ 53,888 | $ — | $ — | $ — | $ — |
| Investment income (loss) | (1,884) | 6,150 | — | — | — | — |
| Benefits paid | 1,795 | 4,000 | 238 | 246 | 268 | 248 |
| Participant contributions | — | — | — | — | 120 | 100 |
| Employer contributions | (3,563) | (3,445) | (238) | (246) | (388) | (348) |
| Plan participants transfer to affiliate | (1,568) | (709) | — | — | — | |
| Ending fair value of plan assets | $ 54,664 | $ 59,884 | $ — | $ — | $ — | $ — |

The funded status of the plans and amounts recognized in the Balance Sheets at December 31 consist of (in thousands):

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plans | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 |
| Regulatory assets | $ 19,099 | $ 18,998 | $ — | $ — | $ — | $ — |
| Current liabilities | $ — | $ — | $ 230 | $ 245 | $ 466 | $ 534 |
| Non-current liabilities | $ 7,255 | $ 7,676 | $ 2,762 | $ 3,173 | $ 4,589 | $ 5,436 |
| Regulatory liabilities | $ — | $ — | $ — | $ — | $ 2,441 | $ 1,758 |

Accumulated Benefit Obligation

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plans | |
|---|---|---|---|---|---|---|
| As of December 31 (in thousands) | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 |
| Accumulated benefit obligation | $ 59,987 | $ 64,782 | $ 2,992 | $ 3,418 | $ 5,055 | $ 5,970 |

Components of Net Periodic Expense

Net periodic expense consisted of the following for the year ended December 31 (in thousands):

| | Defined Benefit Pension Plan | | | Supplemental Non-qualified Defined Benefit Plans | | | Non-pension Defined Benefit Postretirement Healthcare Plans | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Service Cost | $ 516 | $ 545 | $ 606 | $ — | $ — | $ — | $ 193 | $ 206 | $ 204 |
| Interest Cost | 2,194 | 2,341 | 2,499 | 108 | 116 | 122 | 179 | 176 | 187 |
| Expected return on assets | (3,545) | (3,591) | (3,632) | — | — | — | — | — | — |
| Amortization of prior service cost (credits) | 43 | 43 | 43 | — | — | — | (336) | (336) | (337) |
| Recognized net actuarial loss (gain) | 2,063 | 1,230 | 1995 | 103 | 87 | 82 | — | — | — |
| Net periodic expense | $ 1,271 | $ 568 | $ 1,511 | $ 211 | $ 203 | $ 204 | $ 36 | $ 46 | $ 54 |

AOCI

For defined benefit plans, amounts included in AOCI, after-tax, that have not yet been recognized as components of net periodic benefit cost at December 31 were as follows (in thousands):

| | Defined Benefit Pension Plan | | Supplemental Non-qualified Defined Benefit Plans | | Non-pension Defined Benefit Postretirement Healthcare Plans | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2018 | 2017 | 2018 | 2017 |
| Net (gain) loss | $ — | $ — | $ 391 | $ 707 | $ — | $ — |
| Total AOCI | $ — | $ — | $ 391 | $ 707 | $ — | $ — |

Assumptions

| | Defined Benefit Pension Plan | | | Supplemental Non-qualified Defined Benefit Plans | | | Non-pension Defined Benefit Postretirement Healthcare Plans | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Weighted-average assumptions used to determine benefit obligations: | | | | | | | | | |
| Discount rate | 4.40% | 3.71% | 4.27% | 4.30% | 3.62% | 4.12% | 4.28% | 3.60% | 3.84% |
| Rate of increase in compensation levels | 3.52% | 3.43% | 3.47% | N/A | N/A | N/A | N/A | N/A | N/A |
| Weighted-average assumptions used to determine net periodic benefit cost for plan year: | | | | | | | | | |
| Discount rate (a) | 3.71% | 4.27% | 4.63% | 3.62% | 4.12% | 4.29% | 3.60% | 3.84% | 4.03% |
| Expected long-term rate of return on assets (b) | 6.25% | 6.75% | 6.75% | N/A | N/A | N/A | 3.93% | N/A | N/A |
| Rate of increase in compensation levels | 3.43% | 3.47% | 3.57% | N/A | N/A | N/A | N/A | N/A | N/A |

(a) The estimated discount rate for the Defined Benefit Pension Plan is 4.40% for the calculation of the 2019 net periodic pension costs.

(b) The expected rate of return on plan assets is 6.00% for the calculation of the 2019 net periodic pension cost.

The healthcare benefit obligation was determined at December 31 as follows:

| | 2018 | 2017 |
|---|---|---|
| Trend Rate - Medical | | |
| Pre-65 for next year | 6.70% | 7.00% |
| Pre-65 Ultimate trend rate | 4.50% | 4.50% |
| Trend Year | 2027 | 2027 |
| | | |
| Post-65 for next year | 4.94% | 5.00% |
| Post-65 Ultimate trend rate | 4.50% | 4.50% |
| Trend Year | 2026 | 2026 |

Beginning in 2016, the Company changed the method used to estimate the service and interest cost components of the net periodic pension, supplemental non-qualified defined benefit and other postretirement benefit costs. The new method used the spot yield curve approach to estimate the service and interest costs by applying the specific spot rates along the yield curve used to determine the benefit obligations to relevant projected cash outflows. Prior to 2016, the service and interest costs were determined using a single weighted-average discount rate based on hypothetical AA Above Median yield curves used to measure the benefit obligation at the beginning of the period. The change does not affect the measurement of the total benefit obligations as the change in service and interest costs offsets the actuarial gains and losses recorded in other comprehensive income.

The Company changed to the new method to provide a more precise measure of service and interest costs by improving the correlation between the projected benefit cash flows and the discrete spot yield curve rates. The Company accounted for this change as a change in estimate prospectively beginning in 2016.

The following benefit payments, which reflect future service, are expected to be paid (in thousands):

| | Defined Benefit Pension Plan | Supplemental Non-qualified Defined Benefit Plans | Non-pension Defined Benefit Postretirement Healthcare Plans |
|---|---|---|---|
| 2019 | $ 3,660 | $ 230 | $ 466 |
| 2020 | $ 3,774 | $ 227 | $ 534 |
| 2021 | $ 3,924 | $ 322 | $ 566 |
| 2022 | $ 4,031 | $ 319 | $ 577 |
| 2023 | $ 4,102 | $ 315 | $ 554 |
| 2024-2028 | $ 20,759 | $ 1,274 | $ 2,243 |

## (9) RELATED-PARTY TRANSACTIONS

Non-Cash Dividend to Parent

We recorded non-cash dividends to our Parent of $36 million and $42 million in 2018 and 2017 respectively, and decreased the utility money pool note receivable, net by $36 million and $42 million in 2018 and 2017, respectively.

Receivables and Payables

We have accounts receivable and accounts payable balances related to transactions with other BHC subsidiaries. These balances as of December 31 were as follows (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Accounts receivable from affiliates | $ 8,119 | $ 5,664 |
| Accounts payable to affiliates | $ 25,804 | $ 25,653 |

Money Pool Notes Receivable and Notes Payable

We participate in the Utility Money Pool Agreement (the Agreement). Under the Agreement, we may borrow from the pool; however the Agreement restricts the pool from loaning funds to BHC or to any of BHC's non-utility subsidiaries. The Agreement does not restrict us from paying dividends to BHC. Borrowings under the Agreement bear interest at the weighted average daily cost of BHC's external borrowings as defined under the Agreement, or if there are no external funds outstanding on that date, then the rate will be the daily one-month LIBOR plus 1.0%. The cost of borrowing under the Utility Money Pool was 3.06% at December 31, 2018

We had the following balances with the Utility Money Pool as of December 31 (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Money pool notes payable | $ 38,847 | $ 13,487 |

Interest income (expense) relating to the Utility Money Pool for the years ended December 31, was as follows (in thousands):

| | 2018 | 2017 |
|---|---|---|
| Interest income (expense) | $ (401) | $ 272 |

Interest expense allocation from Parent

BHC provides daily liquidity and cash management on behalf of all its subsidiaries. For the years ended December 31, 2018, and 2017, we were allocated $1.3 million and $1.4 million, respectively, of interest expense from BHC.

Other Balances and Transactions

We have the following Power Purchase and Transmission Services Agreements with affiliated entities:

- An agreement, expiring September 3, 2028, with Wyoming Electric to acquire 14.7 MW of the facility output from Happy Jack. Under a separate inter-company agreement expiring on September 3, 2028, Wyoming Electric has agreed to sell up to 15 MW of the facility output from Happy Jack to us.

- An agreement, expiring September 30, 2029, with Wyoming Electric to acquire 20 MW of the facility output from Silver Sage. Under a separate inter-company agreement expiring on September 30, 2029, Wyoming Electric has agreed to sell 20 MW of energy from Silver Sage to us.

- A Generation Dispatch Agreement with Wyoming Electric that requires us to purchase all of Wyoming Electric's excess energy.

- A Wygen III Ground Lease with WDRC expiring in 2050 with three automatic renewal terms of 20 years each.

Related-party Gas Transportation Service Agreement

On October 1, 2014, we entered into a gas transportation service agreement with Wyoming Electric in connection with gas supply for Cheyenne Prairie. The agreement is for a term of 40 years, in which we pay a monthly service and facility fee for firm and interruptible gas transportation.

Related-party Revenue and Purchases

We had the following related-party transactions for the years ended December 31 included in the corresponding captions in the accompanying Statements of Income:

| | 2018 | 2017 |
|---|---|---|
| | (in thousands) | |
| Operating Revenues: | | |
| Energy sold to Cheyenne Light | $ 2,064 | $ 2,481 |
| Rent from electric properties | $ 3,634 | $ 3,680 |
| Horizon Point shared facility revenue | $ 11,211 | $ 1,420 |
| | | |
| Operating Expenses: | | |
| Purchases of coal from WRDC | $ 17,532 | $ 15,948 |
| Purchase of excess energy from Cheyenne Light | $ 511 | $ 601 |
| Purchase of renewable wind energy from Cheyenne Light - Happy Jack | $ 1,942 | $ 1,924 |
| Purchase of renewable wind energy from Cheyenne Light - Silver Sage | $ 3,586 | $ 3,290 |
| Gas transportation service agreement with Cheyenne Light for firm and interruptible gas transportation | $ 364 | $ 393 |

Related-party Corporate Support

We had the following corporate support for the years ended December 31:

| | 2018 | 2017 |
|---|---|---|
| | (in thousands) | |
| Corporate support services and fees from Parent, Black Hills Service Company and Black Hills Utility Holdings | $ 34,578 | $ 27,869 |

Horizon Point Agreement

We have shared facility agreement among South Dakota Electric, Black Hills Service Company, and Black Hills Utility Holdings where there is a cost allocation for the use of the Horizon Point facility that is owned by South Dakota Electric. This cost allocation includes the recovery of and return on allocable property and recovery of incurred administrative service expenses for the operation and maintenance of the Horizon Point facility.

**(10) SUPPLEMENTAL CASH FLOW INFORMATION**

| Years ended December 31, | 2018 | 2017 |
|---|---|---|
| | (in thousands) | |
| Non-cash investing and financing activities - | | |
| Property, plant and equipment acquired with accrued liabilities | $ 15,180 | $ 6,565 |
| Non-cash decrease to money pool note receivable, net | $ (36,000) | $ (42,000) |
| Non-cash dividend to Parent | $ 36,000 | $ 42,000 |
| Cash (paid) refunded during the period for - | | |
| Interest (net of amounts capitalized) | $ (21,988) | $ (21,517) |
| Income taxes | $ (10,394) | $ (12,719) |

**(11) COMMITMENTS AND CONTINGENCIES**

We have the following power purchase and transmission services agreements, not including related party agreements, as of December 31, 2018 (see Note 9 for information on related party agreements):

- A PPA with PacifiCorp, expiring December 31, 2023, for the purchase of 50 MW of electric capacity and energy from PacifiCorp's system. The price paid for the capacity and energy is based on the operating costs of one of PacifiCorp's coal-fired electric generating plants.

- A firm point-to-point transmission service agreement with PacifiCorp that expires December 31, 2023. The agreement provides 50 MW of capacity and energy to be transmitted annually by PacifiCorp.

- An agreement with Thunder Creek for gas transport capacity, expiring October 31, 2019.

- A PPA with Platte River Power Authority (PRPA) to purchase up to 12 MW of wind energy through PRPA's agreement with Silver Sage. This agreement will expire September 30, 2029.

Costs incurred under these agreements were as follows for the years ended December 31 (in thousands):

| Contract | Contract Type | 2018 | 2017 |
|---|---|---|---|
| PacifiCorp | Electric capacity and energy | $ 13,681 | $ 13,218 |
| PacifiCorp | Transmission access | $ 1,742 | $ 1,671 |
| Thunder Creek | Gas transport capacity | $ 633 | $ 633 |
| Platte River Power Authority | Wind energy | $ 223 | $ — |

**Future Contractual Obligations**

The following is a schedule of future minimum payments required under power purchase, transmission services, facility and vehicle leases, and gas supply agreements (in thousands):

| | | |
|---|---|---|
| 2019 | $ | 8,050 |
| 2020 | $ | 7,693 |
| 2021 | $ | 7,059 |
| 2022 | $ | 7,059 |
| 2023 | $ | 7,056 |
| Thereafter | $ | 21,947 |

**Long-Term Power Sales Agreements**

We have the following power sales agreements as of December 31, 2018:

- During periods of reduced production at Wygen III in which MDU owns a portion of the capacity, or during periods when Wygen III is off-line, MDU will be provided with 25 MW from our other generation facilities or from system purchases with reimbursement of costs by MDU. This agreement expires January 31, 2023.

- An agreement to serve MDU capacity and energy up to a maximum of 50 MW in excess of Wygen III ownership. This agreement expires December 31, 2023.

- During periods of reduced production at Wygen III in which the City of Gillette owns a portion of the capacity, or during periods when Wygen III is off-line, we will provide the City of Gillette with its first 23 MW from our other generating facilities or from system purchases with reimbursement of costs by the City of Gillette. Under this agreement, which expires September 3, 2019, South Dakota Electric will also provide the City of Gillette their operating component of spinning reserves.

- A PPA with MEAN expiring May 31, 2028. This contract is unit-contingent on up to 10 MW from Neil Simpson II and up to 10 MW from Wygen III based on the availability of these plants. The capacity purchase requirements decrease over the term of the agreement.

- An agreement through December 31, 2021 to provide 50 MW of energy to Macquarie Energy, LLC during heavy and light load timing intervals.

**Environmental Matters**

We are subject to costs resulting from a number of federal, state and local laws and regulations which affect future planning and existing operations. They can result in increased capital expenditures, operating and other costs as a result of compliance, remediation and monitoring obligations. Due to the environmental issues discussed below, we may be required to modify, curtail, replace or cease operating certain facilities or operations to comply with statutes, regulations and other requirements of regulatory bodies.

*Solid Waste Disposal*

Various materials used at our facilities are subject to disposal regulations. Our Osage plant, permanently retired on March 21, 2014, had an on-site ash impoundment that was near capacity. An application to close the impoundment was approved on April 13, 2012. Site closure work was completed in 2013 with the state providing closure certification in 2014. Post closure monitoring activities will continue for 30 years following the closure certification date.

In September 2013, Osage also received a permit to close the small industrial rubble landfill. Site work was completed with the state providing closure certification in 2014. Post closure monitoring will continue for 30 years following the closure certification date.

**Legal Proceedings**

In the normal course of business, we are subject to various lawsuits, actions, proceedings, claims and other matters asserted under laws and regulations. We believe the amounts provided in the financial statements to satisfy alleged liabilities are adequate in light of the probable and estimable contingencies. However, there can be no assurance that the actual amounts required to satisfy alleged liabilities from various legal proceedings, claims and other matters discussed, and to comply with applicable laws and regulations will not exceed the amounts reflected in the financial statements.

In the normal course of business, we enter into agreements that include indemnification in favor of third parties, such as information technology agreements, purchase and sale agreements and lease contracts. We have also agreed to indemnify our directors, officers and employees in accordance with our articles of incorporation, as amended. Certain agreements do not contain any limits on our liability and therefore, it is not possible to estimate our potential liability under these indemnifications. In certain cases, we have recourse against third parties with respect to these indemnities. Further, we maintain insurance policies that may provide coverage against certain claims under these indemnities.

**(12) SUBSEQUENT EVENT**

Management has evaluated and concluded that there were no significant subsequent events occurring after December 31, 2018 to February 22, 2019, the date the Black Hills Power's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 18, 2019. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.