

Bonavista Energy Corporation Replaces 189% of 2017 Production with the Addition of 49.8 MMboe of Proved Plus Probable Reserves

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(TSX:BNP)

CALGARY, Jan. 31, 2018 /CNW/ - [Bonavista Energy Corp.](#) ("Bonavista") is pleased to report that our 2017 exploration development ("E&D") program has resulted in a finding and development ("F&D") cost of \$7.60 per barrel of oil equivalent on a proved plus probable basis. When combined with our acquisition and divestiture program ("A&D"), finding, development and acquisition ("FD&A") costs were \$7.56 per boe on a proved plus probable basis, in each case including changes in future development costs ("FDC").

2017 Reserves Highlights:

The success we have experienced in the execution of our 2017 capital program continues to reinforce the quality and quantity of the opportunities that exist in our core areas as demonstrated by the highlights listed below:

- Replaced 189% of 2017 production with the addition of 49.8 MMboe of proved plus probable reserves;
- Proved plus probable reserves growth of six percent to 437.7 MMboe;
- Achieved a proved plus probable FD&A recycle ratio of 1.8:1, despite negative revisions of 2.4 MMboe due to low oil prices;
- Oil and natural gas liquids reserves comprised 29% of proved plus probable reserves;
- Invested \$96 million in 2017 to increase proved developed producing and proved plus probable reserves by 59% and 28% respectively at our Ansell Wilrich play in our Deep Basin core area;
- Invested \$51 million in 2017 to increase proved developed producing and proved plus probable reserves by 28% and 28% respectively at our Morningside Falher play in our West Central core area; and
- Using the independent reserves evaluation effective December 31, 2017, the PV10 before taxes of our proved plus probable reserves of \$2,451 million, net of long-term debt (net of adjusted working capital) of approximately \$840 million equated to \$6.28 per common share (based on 256 million equivalent basic common shares outstanding). With the addition of our internally estimated total land value of \$138 million, our net asset value would be approximately \$6.82 per common share.

Operational and Financial Update:

During the fourth quarter of 2017, we produced 74,799 boe per day representing growth from the previous quarter of 72,156 boe per day. For the year ended December 31, 2017, we invested \$282 million into our two core areas drilling 61 (56.7 net) wells resulting in an average production of 72,156 boe per day. Currently we are producing approximately 74,000 boe per day. Specific operational highlights include the following:

- Annual and fourth quarter production growth of five percent and eight percent respectively;
- Reduced annual 2017 cash costs by five percent to \$8.92 per boe when compared to the same period in 2016; and
- Reduced our cost to add production through our E&D program by eight percent to \$12,500 per boe per day when compared to 2016.

2017 Independent Reserves Evaluation:

The evaluation of our reserves was done in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserves information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR on or before March 31, 2018.

Independent reserve evaluators, GLJ Petroleum Consultants Ltd. ("GLJ") evaluated 100% of our total net present value reserves in their report dated January 31, 2018 and effective December 31, 2017 (the "GLJ Report").

Reserves Summary:

The following tables summarize our working interest oil, natural gas liquids and natural gas reserves and the net present values ("NPV") of future net revenue for these reserves (before taxes) using forecast prices and costs as set forth in the GLJ Report.

	Natural Gas ⁽²⁾	Crude Oil ⁽³⁾	Natural Gas Liquids	Oil Equivalent Total Reserves	NPV of Future Net Revenue Discounted at		
Gross Reserves ⁽¹⁾ :					5%	10%	15%
	(MMcf)	(Mbbls)	(Mbbls)	(Mboe)	(\$000's)	(\$000's)	(\$000's)
Proved:							
Proved Producing	642,376	4,489	43,267	154,819	1,409,379	1,156,575	980,204
Proved Non-Producing	33,151	325	1,808	7,658	51,707	42,041	34,900
Proved Undeveloped	479,484	1,548	31,069	112,531	719,599	448,841	284,435
Total Proved	1,155,012	6,362	76,145	275,008	2,180,686	1,647,457	1,299,538
Probable	722,009	2,905	39,495	162,735	1,339,358	804,384	530,395
Total Proved plus Probable	1,877,021	9,266	115,640	437,743	3,520,044	2,451,840	1,829,933

(1) Amounts may not add due to rounding.

(2) Includes conventional natural gas, shale natural gas and coal bed methane.

(3) Includes light, medium, heavy and tight oil.

The reserves evaluation was based on GLJ forecast pricing and foreign exchange rates at January 1, 2018 as outlined below. The GLJ January 1, 2018 forecast pricing for natural gas at AECO and West Texas Intermediate ("WTI") oil for 2018 are CDN\$2.20/MMBtu and US\$59.00/bbl respectively. This represents a 29% reduction in forecast 2018 natural gas pricing and no change to the 2018 forecast WTI oil price when compared to GLJ's forecast pricing one year ago.

Price Forecast	Edmonton Light Crude Oil	WTI Oil	AECO Natural Gas	Exchange Rate
	(CDN\$/bbl)	(US\$/bbl)	(CDN\$/MMBtu)	(US\$/CDN\$)
2018	70.25	59.00	2.20	0.790
2019	70.25	59.00	2.54	0.790
2020	70.31	60.00	2.88	0.800
2021	72.84	63.00	3.24	0.810
2022	75.61	66.00	3.47	0.820
2023	78.31	69.00	3.58	0.830
2024	81.93	72.00	3.66	0.830
2025	85.54	75.00	3.73	0.830
2026	88.35	77.33	3.80	0.830
2027	90.22	78.88	3.88	0.830
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.830

Reserves Reconciliation:

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS ⁽¹⁾						
	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)
December 31, 2016	7,511	3,111	10,622	417	130	547
Extensions and Improved Recovery ⁽²⁾	355	317	673	—	—	—
Technical Revisions	(842)	(591)	(1,433)	7	2	8
Discoveries	—	—	—	—	—	—
Acquisitions	2	1	3	—	—	—
Dispositions	(165)	(57)	(222)	—	—	—
Economic Factors	(45)	(9)	(53)	(2)	—	(2)
Production	(854)	—	(854)	(22)	—	(22)
December 31, 2017	5,962	2,773	8,735	400	132	532

	NATURAL GAS			NATURAL GAS LIQUIDS		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(Mbbbls)	(Mbbbls)	(Mbbbls)
December 31, 2016	1,128,147	592,890	1,721,037	77,231	38,966	116,197
Extensions and Improved Recovery ⁽²⁾	157,950	141,426	299,376	5,213	2,397	7,611
Technical Revisions	(14,927)	(18,031)	(32,958)	912	(1,873)	(961)
Discoveries	—	—	—	—	—	—
Acquisitions	9,000	19,890	28,890	257	517	774
Dispositions	(8,381)	(8,452)	(16,832)	(340)	(341)	(681)
Economic Factors	(5,458)	(5,714)	(11,172)	(289)	(172)	(461)
Production	(111,319)	—	(111,319)	(6,841)	—	(6,841)
December 31, 2017	1,155,012	722,009	1,877,021	76,145	39,495	115,640

	OIL EQUIVALENT		
	Proved	Probable	Proved Plus Probable
	(Mboe)	(Mboe)	(Mboe)
December 31, 2016	273,183	141,022	414,205
Extensions and Improved Recovery ⁽²⁾	31,894	26,286	58,181
Technical Revisions	(2,411)	(5,468)	(7,879)
Discoveries	—	—	—
Acquisitions	1,759	3,833	5,592
Dispositions	(1,902)	(1,806)	(3,708)
Economic Factors	(1,245)	(1,133)	(2,378)
Production	(26,270)	—	(26,270)
December 31, 2017	275,008	162,735	437,743

(1) Amounts may not add due to rounding.

(2) Infill drilling, improved recovery and extensions have been grouped as extensions and improved recovery as per NI 51-101.

Reserve Life Index ("RLI"):

Our business plan is to create premium shareholder value through the efficient development of high quality oil and natural gas assets. The profitable growth of our reserves coupled with the sustainable production of these reserves will generate long-term returns for our shareholders.

In 2017, our proved plus probable RLI increased by six percent to 15.2 years demonstrating the sustainable balance that exists between our capital program, our reserves additions and our production levels.

The following table highlights our historical RLI.

Reserve Life Index (Years)⁽¹⁾ 2017 2016 2015 2014 2013

Total Proved 10.3 10.5 9.7 9.4 9.1

Total Proved plus Probable 15.2 14.4 14.1 13.1 13.2

(1) Calculated based on the amount for the relevant reserves category divided by the production forecast for the applicable year prepared by GLJ.

Future Development Costs:

Changes in forecast FDC occur annually and result from development, acquisition and disposition activities. Future development cost estimates reflect GLJ's best estimate of the costs required to bring the proved and proved plus probable reserves on production. We have 219.7 MMboe proved plus probable undeveloped reserves assigned to \$1,373.1 million of total undiscounted FDC. At a cost of \$6.25 per boe, these future reserves generate \$942 million of net present value discounted at 10%.

Total undiscounted FDC as a ratio of trailing average three year E&D expenditures of \$252.3 million is 5.6:1 times at year-end 2017, representing prudent and sustainable development forecasts.

The following table sets forth the schedule of FDC required to develop these future reserves (using forecast prices and costs).

Future Development Costs⁽¹⁾⁽²⁾ Total Proved Total Proved plus Probable

(\$ thousands) (\$ thousands)

2018	126,229	176,563
2019	295,740	402,978
2020	227,282	287,325
2021	106,207	211,703
2022	120,880	214,624
Remaining	23,015	121,947
Total (Undiscounted)	899,352	1,415,138
Total (Discounted at 10%)	720,616	1,099,287

(1) Amounts may not add due to rounding.

(2) Future development costs include both developed and undeveloped reserves.

Reserves Performance Ratios:

The following tables highlight Bonavista's reserves, F&D costs and FD&A costs and the associated recycle ratios for the trailing three years.

Bonavista considers recycle ratio an important measure of long-term profitability. It is measured by dividing the operating netback by the F&D costs per boe for the year. Bonavista has delivered a three year weighted average F&D recycle ratio of 2.0:1 and FD&A recycle ratio of 3.0:1 for proved plus probable reserves including revisions and changes in FDC.

	2017	2016	2015
Reserves (Mboe):			
Proved producing	154,819	155,907	162,072
Total proved	275,008	273,183	262,224
Proved plus probable	437,743	414,205	406,494

Capital Expenditures (\$ millions):

E&D	289.0	153.9	313.9
Dispositions, net of acquisitions	(7.8)	(167.9)	(30.6)
Total capital expenditures	281.2	(14.0)	283.4

Operating Netback (\$/boe)⁽¹⁾:

Current year	13.85	13.44	16.16
Three-year weighted average	14.55	17.54	19.72

(1) Amounts may not add due to rounding.

Finding and Development Costs:	2017	2016	2015
Proved Producing:			
Change in FDC (\$ millions)	(11.818)	(0.173)	(0.339)
Reserves additions (MMboe)	25.902	15.831	26.252
F&D costs (\$/boe) ⁽²⁾	10.70	9.71	11.94
F&D recycle ratio ⁽³⁾	1.3	1.4	1.4
F&D three-year weighted costs (\$/boe) ⁽²⁾	10.95	12.04	13.57
F&D recycle ratio three-year weighted average ⁽³⁾	1.3	1.5	1.5
Total Proved:			
Change in FDC (\$ millions)	(41.615)	86.377	(188.683)
Reserves additions (MMboe)	28.237	26.972	20.346
F&D costs (\$/boe) ⁽²⁾	8.76	8.91	6.15
F&D recycle ratio ⁽³⁾	1.6	1.5	2.6
F&D three-year weighted costs (\$/boe) ⁽²⁾	8.11	10.40	12.21
F&D recycle ratio three-year weighted average ⁽³⁾	1.8	1.7	1.6
Total Proved plus Probable:			
Change in FDC (\$ millions)	75.423	60.902	(183.483)
Reserves additions (MMboe)	47.923	30.824	17.975
F&D costs (\$/boe) ⁽²⁾	7.60	6.97	7.26
F&D recycle ratio ⁽³⁾	1.8	1.9	2.2
F&D three-year weighted costs (\$/boe) ⁽²⁾	7.34	9.11	10.65
F&D recycle ratio three-year weighted average ⁽³⁾	2.0	1.9	1.9

Finding, Development and Acquisition Expenditures: 2017 2016 2015

Proved Producing:

Change in FDC (\$ millions)	(13.638)	(2.269)	4.667
Reserves additions (MMboe)	25.182	18.879	21.539
FD&A costs (\$/boe) ⁽²⁾	10.62	(0.86)	13.37
FD&A recycle ratio ⁽³⁾	1.3	(15.6)	1.2
FD&A three-year weighted costs (\$/boe) ⁽²⁾	8.22	9.69	13.35
FD&A recycle ratio three-year weighted average ⁽³⁾	1.8	1.8	1.5

Total Proved:

Change in FDC (\$ millions)	(38.762)	111.576	(186.034)
Reserves additions (MMboe)	28.095	36.004	15.388
FD&A costs (\$/boe) ⁽²⁾	8.63	2.71	6.32
FD&A recycle ratio ⁽³⁾	1.6	5.0	2.6
FD&A three-year weighted costs (\$/boe) ⁽²⁾	5.50	7.81	12.10
FD&A recycle ratio three-year weighted average ⁽³⁾	2.6	2.2	1.6

Total Proved plus Probable:

Change in FDC (\$ millions)	95.119	(3.821)	(198.572)
Reserves additions (MMboe)	49.808	32.756	8.618
FD&A costs (\$/boe) ⁽²⁾	7.56	(0.55)	9.84
FD&A recycle ratio ⁽³⁾	1.8	(24.4)	1.6
FD&A three-year weighted costs (\$/boe) ⁽²⁾	4.86	6.42	10.42
FD&A recycle ratio three-year weighted average ⁽³⁾	3.0	2.7	1.9

(1) Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, transportation and operating expenditures, calculated on a per boe basis.

(2) Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis.

(3) Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs per boe.

Hedging & Diversification:

Bonavista has prudently reduced its AECO exposure by diversifying to non-AECO markets and strengthening its hedging position. Currently, only 23% of our forecasted natural gas volumes and nine percent of our 2018 forecasted petroleum and natural gas revenues are exposed to the AECO spot market in 2018. Currently, Bonavista has hedged approximately 50% of our forecasted 2018 natural gas production at an AECO price of \$3.07 per mcf.

General

Bonavista is focused on creating premium shareholder value through the efficient development of high quality oil and natural gas assets.

This news release contains certain financial information that has been derived from our unaudited consolidated financial statements for the year ended 2017.

Oil and Gas Advisories

The reserves estimates contained in this news release represent our gross reserves as at December 31, 2017 and are defined under NI 51-101, as our interest before deduction of royalties and without including any of our royalty interests. It should not be assumed that the present worth of estimated future net revenues presented in the tables above represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

All future net revenues are estimated using forecast prices, arising from the anticipated development and production of our reserves, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs and are stated prior to provision for interest and general and administrative expenses. Future net revenues have been presented on a before tax basis. Estimated values of future net revenue disclosed herein do not represent fair market value.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

This news release contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio", "finding and development costs" or "F&D costs", "F&D recycle ratio", "finding development and acquisition costs" or "FD&A costs", "FD&A recycle ratio" "operating netbacks", "reserve life index" and "net asset value". These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this news release to provide readers with additional measures to evaluate Bonavista's performance, however, such measures are not reliable indicators of Bonavista's future performance and future performance may not compare to Bonavista's performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide securityholders with measures to compare Bonavista's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this news release, should not be relied upon for investment or other purposes.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities in the year by the change in reserves from the prior year for the reserve category. Finding development and acquisition costs are calculated on a per boe basis by dividing

the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category. Both finding and development costs and finding development and acquisition costs take into account reserves revisions during the year on a per boe basis. The aggregate of the F&D costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this news release because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure.

Cost to add production is determined by dividing the yearly capital E&D expenditures by the year-end production adds. The year-end production adds are determined by subtracting the current year exit production from the prior year exit production, adjusted for any acquisition or disposition volumes, added to the base yearly decline volumes.

Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs per boe for the year. F&D recycle ratio is calculated by dividing the netback for the period by the F&D costs per boe for the particular reserve category. FD&A recycle ratio is calculated by dividing the netback for the period by the FD&A costs per boe for the particular reserve category.

Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, transportation and operating expenditures calculated on a per boe basis (see also "Non-GAAP Measures). Reserve life index is calculated based on the amount for the relevant reserves category divided by the production forecast for the applicable year prepared by GLJ.

Our estimated net asset value is based on the estimated net present value of all future net revenue from our proved plus probable reserves, discounted at 10%, before tax, as estimated by GLJ, at year-end, with and without the estimated value of our undeveloped acreage, and less long-term debt and adjusted working capital. Common share values in our net asset value per share metric are calculated by including our outstanding common shares and exchangeable shares which are converted into common shares on certain terms and conditions.

The following abbreviations used in this news release have the meanings set forth below:

Bbls barrels

Mbbls thousand barrels

Boe barrels of oil equivalent

Mboe thousand barrels of oil equivalent

MMboe million barrels of oil equivalent

Mcf thousand cubic feet

MMcf million cubic feet

MMBtu million British Thermal Units

\$000's thousands of dollars

Forward Looking Statements

Corporate information provided herein contains forward-looking information relating to our plans and other aspects of our anticipated future operations, management focus, strategies and business opportunities

including statements about our plans to create premium shareholder value, generate long term returns to our shareholders and to profitably grow our reserves coupled with the sustainable production of these reserves, estimated 2018 forecasted volumes and revenues subject to hedging, industry conditions, commodity prices and the quality and reliability of our assets.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking information is based on certain key expectations and assumptions made by our management, including expectations and assumptions concerning prevailing commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; performance; business prospects and opportunities; the availability and cost of financing, labour and services; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions, ability to market oil and natural gas successfully and our ability to access capital.

Although we believe that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Bonavista can give no assurance that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature they involve inherent risks and uncertainties. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, the forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits that we will derive therefrom. Management has included the above summary of assumptions and risks related to forward-looking information provided in this news release in order to provide securityholders with a more complete perspective on our future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). Jason E. Skehar, President & CEO or Bruce W. Jensen, COO or Dean M. Kobelka, Vice President, Finance & CFO or Berk Sumen, Investor Relations Lead; [Bonavista Energy Corp.](http://www.bonavistaenergy.com), 1500, 525 - 8th Avenue SW, Calgary, AB T2P 1G1, Phone: (403) 213-4300, Website: www.bonavistaenergy.com

~~These forward-looking statements are made as of the date of this news release and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.~~

~~<https://www.rohstoff-welt.de/news/289480--Bonavista-Energy-Corporation-Replaces-189Prozent-of-2017-Production-with-the-Addition-of-49.8-MMboe-of-Prov>~~

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This news release contains the term "operating netbacks", "cash costs", and "long-term debt (net of adjusted working capital)" which do not have standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Operating netbacks and cash costs are used by Bonavista to analyze operating performance. Bonavista believes these benchmarks are key measures of profitability and overall sustainability. These terms are commonly used in the oil and gas industry.

Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, transportation and operating expenditures calculated on a per boe basis. Cash costs are equal to the total of operating, transportation, general and administrative, and financing expenses. Long-term debt (net of adjusted working capital) means total debt adjusted to exclude associated current assets or liabilities from financial instrument contracts and decommissioning liabilities, also known as total net debt.

SOURCE [Bonavista Energy Corp.](http://www.bonavistaenergy.com)