

SURGE ENERGY INC. ANNOUNCES FOURTH QUARTER AND YEAR END FINANCIAL RESULTS FOR 2024; 2024 YEAR END RESERVES; AND OPERATIONAL UPDATES

CALGARY, AB, March 5, 2025 /CNW/ - Surge Energy Inc. ("Surge", "SGY", or the "Company") (TSX: SGY) is pleased to announce its financial and operating results for the quarter and year ended December 31, 2024, and its year end 2024 reserves as independently evaluated by Sproule.



Surge's disciplined operating strategy involves focusing development capital to high operating netback, low cost, light and medium gravity, conventional crude oil reservoirs with low recovery factors. Following the strategic non-core divestitures announced in 2024, over 90 percent of the Company's production now comes from the Sparky and SE Saskatchewan core areas, which have been independently evaluated as two of the top four crude oil plays in Canada¹ based on per well payout economics.

In Q4/24 Surge achieved better than anticipated average production of 24,319 boepd (88 percent liquids), exceeding the Company's budgeted 2024 exit production guidance of 24,000 boepd. Additionally, Surge achieved annual average production in 2024 of 24,158 boepd (87 percent liquids).

Based on better than anticipated Q1/25 drilling results to date in Surge's Sparky and SE Saskatchewan core areas, the Company's current production is exceeding Management's 2025 budgeted average production guidance level of 22,500 boepd (ie. post the 2024 non-core dispositions).

During Q4/24 WTI crude oil prices decreased by approximately US\$5 per barrel, with WTI averaging US\$70.27 per barrel in Q4/24, as compared to US\$75.10 per barrel in Q3/24. Despite this drop in quarterly crude oil prices, Surge's adjusted funds flow per share ("AFF")² actually increased by 5 percent to \$76.1 million in Q4/24, as compared to \$72.7 million in Q3/24. Surge was able to achieve higher AFF in Q4/24 as compared to Q3/24 due to higher than budgeted production levels, as well as interest expense savings relating to the issuance of Surge's new \$175 million senior unsecured 5 year term loan debt financing in late Q3/24. In Q4/24, the Company generated cash flow from operating activities, inclusive of changes in non-cash working capital, of \$64.8 million, as compared to \$73.4 million in Q3/24.

In the fourth quarter of 2024, Surge paid \$13.2 million in dividends to shareholders, which represents only 17 percent of AFF generated in Q4/24. Surge also returned an additional \$6.2 million to shareholders in Q4/24 through its ongoing share buyback program under the Company's Normal Course Issuer Bid ("NCIB"), repurchasing over 1,050,000 shares. In total, Surge returned \$19.4 million directly to shareholders during the fourth quarter of 2024.

In 2024, Surge generated \$278.6 million of cash flow from operating activities, with WTI averaging US\$75.72 per barrel. This represents a 5 percent increase over the \$266.1 million of cash flow from operating activities generated in 2023, when WTI averaged US\$77.62 per barrel. Similarly, AFF increased one percent to \$294.1 million in 2024, as compared to \$291.8 million in 2023.

Surge generated free cash flow ("FCF")² of \$99 million in 2024, representing 34 percent of the Company's 2024 AFF of \$294.1 million. Surge returned a total of \$61.2 million to shareholders in 2024 pursuant to the Company's monthly base dividend (currently \$0.52 per share, per annum) and share buybacks.

In early January 2025, Surge Management strategically locked in attractive crude oil fixed price hedges well above Surge's budget price of US\$70 WTI, in order to protect the Company's 2025 free cash flow profile. These fixed price oil hedges are set forth below:

- 7,000bbl/d at an average price of US\$75.65/bbl for February and March 2025; and
- 5,500bbl/d at an average price of US\$73.76/bbl for Q2/25; and
- 4,000bbl/d at an average price of US\$72.85/bbl for Q3/25.

Additionally, Surge strategically hedged approximately 60 percent of its net (after royalty) Western Canadian Select ("WCS") differential exposure at an average of US\$13.92 per barrel for all of 2025. The Company also hedged approximately 40 percent of its 2025 Edmonton light oil differential ("MSW") exposure at US\$3.70 per barrel. For further details on the Company's ongoing risk management positions, please see the Company's Q4/24 Management Discussion & Analysis.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

Additional financial and operating highlights for the quarter and year ended December 31, 2024 include:

- Generated AFF of \$76.1 million in Q4/24;
- Generated cash flow from operating activities of \$64.8 million in Q4/24;
- Reduced net debt² by \$42.9 million in 2024 to \$247.1 million, a decrease of 15 percent;
- Completed the strategic repositioning of the Company's debt capital structure with the closing of a \$175 million, 5 year term, senior unsecured note financing ("Senior Unsecured Notes"), which matures in September 2029;
- Further strengthened Surge's financial position with an increase of \$40 million to the Company's first-lien revolving credit facility in Q3/24, which now stands undrawn at \$250 million;
- Distributed cash dividends to shareholders in the amount of \$50.0 million in 2024 and returned an additional \$11.2 million to shareholders through the Company's ongoing NCIB, repurchasing over 1.82 million shares in 2024;
- On a combined basis, Surge provided direct returns of approximately \$61.2 million to shareholders in 2024 through the base dividend and the NCIB share repurchases;
- Reduced net operating expenses² by \$2.69 per boe over the course of 2024, from \$21.81 per boe in Q1/24 to \$19.12 per boe in Q4/24. This represents a decrease in net operating expenses of more than 10 percent over the year;
- In 2024, the Company continued to validate and expand Surge's exciting new Sparky crude oil discovery at Hope Valley ("Hope Valley"), drilling 8 gross (8.0 net) additional wells at the property. Surge now estimates that the Company has over 80 multi-lateral drilling locations³ at Hope Valley, and is increasingly encouraged by the consistency of its ongoing drilling results as it moves into the full development phase of this new Sparky discovery; and
- On December 19, 2024, Surge disposed of its gas weighted non-core assets in the Valhalla area of Alberta for cash proceeds of \$9.5 million.

FINANCIAL AND OPERATING HIGHLIGHTS

FINANCIAL AND OPERATING HIGHLIGHTS (\$000s except per share and per boe)	Three Months Ended December 31,			Years Ended December 31,		
	2024	2023	% Change	2024	2023	% Change
Financial highlights						
Oil sales	158,405	160,755	(1) %	635,618	640,389	(1) %
NGL sales	3,378	3,619	(7) %	14,218	13,052	9 %
Natural gas sales	1,389	4,079	(66) %	6,867	16,934	(59) %
Total oil, natural gas, and NGL revenue	163,172	168,453	(3) %	656,703	670,375	(2) %
Cash flow from operating activities	64,838	79,712	(19) %	278,647	266,141	5 %
Per share - basic (\$)	0.64	0.79	(19) %	2.76	2.69	3 %
Per share - diluted (\$)	0.64	0.78	(18) %	2.72	2.63	3 %
Adjusted funds flow ^a	76,121	77,001	(1) %	294,123	291,846	1 %
Per share - basic (\$) ^a	0.75	0.77	(3) %	2.92	2.95	(1) %
Per share - diluted (\$)	0.75	0.75	— %	2.87	2.89	(1) %
Net income (loss) ^b	(2,656)	(29,676)	(91) %	(53,716)	15,751	nm
Per share - basic (\$)	(0.03)	(0.30)	(90) %	(0.53)	0.16	nm
Per share - diluted (\$) ^d	(0.03)	(0.29)	(90) %	(0.53)	0.16	nm
Expenditures on property, plant and equipment	58,277	61,305	(5) %	195,103	181,572	7 %
Net acquisitions and dispositions	(8,868)	3,813	nm ^c	(42,389)	1,670	nm
Net capital expenditures	49,409	65,118	(24) %	152,714	183,242	(17) %

Net debt ^a , end of period	247,126	290,070	(15) %	247,126	290,070	(15) %
Operating highlights						
Production:						
Oil (bbls per day)	20,675	20,741	— %	20,228	20,434	(1) %
NGLs (bbls per day)	777	808	(4) %	818	704	16 %
Natural gas (mcf per day)	17,199	21,005	(18) %	18,672	19,801	(6) %
Total (boe per day) (6:1)	24,319	25,050	(3) %	24,158	24,438	(1) %
Average realized price (excluding hedges):						
Oil (\$ per bbl)	83.28	84.24	(1) %	85.85	85.86	— %
NGL (\$ per bbl)	47.26	48.68	(3) %	47.49	50.78	(6) %
Natural gas (\$ per mcf)	0.88	2.11	(58) %	1.00	2.34	(57) %
Netback (\$ per boe)						
Petroleum and natural gas revenue	72.93	73.09	— %	74.27	75.15	(1) %
Realized gain (loss) on commodity and FX contracts	(0.12)	1.02	nm	(0.40)	(0.35)	14 %
Royalties	(13.27)	(13.55)	(2) %	(13.56)	(13.40)	1 %
Net operating expenses ^a	(19.12)	(19.90)	(4) %	(20.02)	(21.13)	(5) %
Transportation expenses	(1.39)	(1.48)	(6) %	(1.29)	(1.54)	(16) %
Operating netback ^a	39.03	39.18	— %	39.00	38.73	1 %
G&A expense	(2.33)	(2.19)	6 %	(2.34)	(2.15)	9 %
Interest expense	(2.68)	(3.58)	(25) %	(3.40)	(3.86)	(12) %
Adjusted funds flow ^a	34.02	33.41	2 %	33.26	32.72	2 %
Common shares outstanding, end of period	100,382	100,314	— %	100,382	100,314	— %
Weighted average basic shares outstanding	101,142	100,314	1 %	100,832	98,790	2 %
Stock-based compensation dilution ^d	745	1,808	(59) %	1,568	2,227	(30) %
Weighted average diluted shares outstanding	101,887	102,122	— %	102,400	101,017	1 %

^a This is a non-GAAP and other financial measure which is defined in Non-GAAP and Other Financial Measures.

^b The twelve months ended December 31, 2024 includes a non-cash impairment charge of \$96.5 million. The three and twelve months ended December 31, 2023 includes a non-cash impairment charge of \$59.2 million.

^c The Company views this change calculation as not meaningful, or "nm".

^d Dilution is not reflected in the calculation of net loss for the three months and year ended December 31, 2024.

OPERATIONS UPDATE

2024 Operations Overview

In 2024 Surge successfully drilled a total of 83 gross (73.1 net) wells, spending a total of \$195.1 million including expenditures on facilities, equipment, land, and capitalized G&A. Drilling operations were focused entirely on the Company's medium and light gravity crude oil assets in its core Sparky and SE Saskatchewan areas, where 40 gross (40.0 net) and 43 gross (33.1 net) wells were drilled, respectively.

In 2024 Surge drilled 12 gross (12.0 net) multi-lateral wells utilizing the application of modern open hole drilling technology in its Sparky core area, including 8 gross (8.0 net) multi-lateral wells drilled at the Company's recent Hope Valley discovery.

Several milestones were achieved in 2024 with respect to the development of Hope Valley. Six of the eight Hope Valley wells were drilled with a 12-leg, open hole design, accessing an average of 15,530 meters of Sparky reservoir per well. All six of these wells are currently on production, with an average initial 60 day production rate of 210 bopd per well. Two of the wells drilled were step-out wells, drilled seven miles to the Northwest of the initial discovery wells, utilizing an 8-leg, open hole design. These two step-out wells are now on production with an average 60 day production rate of 191 bopd, which compares favorably to the initial discovery wells³.

Surge Management is increasingly encouraged by the repeatability and consistency of the drilling results at Hope Valley as the Company continues to move this core oil asset into the development phase. In 2024, Surge successfully completed the construction of a multi-well battery and conducted a 42-square-kilometer 3D seismic survey. This complemented the Company's existing 3D seismic dataset, further mitigating risks for future locations and setting the stage for future development. Surge currently owns 32.5 sections of land in Hope Valley, the majority of which is covered by proprietary 3D seismic data. With the integration of seismic data and geological mapping, the Company now internally estimates over 80 net multi-lateral Sparky drilling locations remaining on these lands.

The 2024 SE Saskatchewan drilling program focused primarily on the Frobisher formation, with a total of 43 gross (33.1 net) wells drilled. This included the use of modern open-hole multi-lateral drilling techniques, with 18 gross (15.1 net) wells drilled as stacked multi-lateral wells, each consisting of two to three open-hole legs. Additionally, the program included 5 gross (4.8 net) single-leg Frobisher wells and 3 gross (2.3 net) Frobisher re-entries. Over the last three years, Surge has achieved industry leading results with average 90 day production rates of 195 bopd for all Frobisher wells drilled in the Province of Saskatchewan between January 1, 2022 and December 31, 2024⁴.

In Q4/24, Surge achieved an average production rate of 24,319 boepd (88 percent liquids), exceeding the Company's 2024 public guidance production exit rate of 24,000 boepd.

Surge also achieved record annual production volumes in both its Sparky and SE Saskatchewan core operating areas in 2024. Sparky annual volumes grew 3 percent to average approximately 11,250 boepd in 2024, and SE Saskatchewan annual volumes increased more than 8 percent to an average 2024 production level of greater than 8,000 boepd.

2025 Operations Update

Surge has continued the Company's operational momentum into early 2025, with three drilling rigs active in its Sparky and SE Saskatchewan core areas. Surge plans to drill 65 net wells in 2025, with 100 percent of the 2025 drilling budget expected to be allocated to these two core areas. The 2025 drilling program is comprised of 34 gross (34.0 net) Sparky wells and 35 gross (31.0 net) SE Saskatchewan wells, with total capital expenditures budgeted at \$170 million.

In the Sparky core area, Surge's 2025 capital program will consist of 19 gross (19.0 net) single-leg multi-frac horizontal wells and 15 gross (15.0 net) multi-lateral wells. Management's focus in 2025 is on the continued growth of Surge's multi-lateral well footprint in the Mannville stack, with approximately 50 percent of the Sparky core area drilling capital directed to Mannville multi-lateral development. In 2025, Surge intends to have a dedicated rig drilling multi-lateral wells in Hope Valley throughout the entire year, including drilling through spring breakup.

In the SE Saskatchewan core area, Surge is currently budgeting to drill 35 gross (31.0 net) conventional Mississippian horizontal wells, with 23.0 net wells targeting the Frobisher formation, and 8.0 net wells targeting the Midale and Lodgepole formations. Over the past several years, Surge has successfully optimized reservoir contact by drilling two and three leg, vertically stacked multi-lateral wells targeting discrete pay zones within the Frobisher formation. In 2025, 20 gross (17.0 net) wells, representing 74 percent of planned Frobisher drills for the year, will be drilled as stacked multi-lateral horizontal wells.

The Company commenced its winter drilling program in late December of 2024, and has now completed the drilling of 9 gross (9.0 net) Sparky locations and 7 gross (6.8 net) operated wells in SE Saskatchewan. All wells are anticipated to be completed and on production by early Q2/25.

2024 YEAR END RESERVES HIGHLIGHTS

Surge is pleased to announce the results of the independent reserves evaluation of the Company's crude oil and natural gas assets, dated February 7, 2025 and effective December 31, 2024, in compliance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and in accordance with the Canadian Oil and Gas Evaluation Handbook (the "Reserve Report").

Building on the successful 2024 drilling program in the Sparky and SE Saskatchewan core areas, Surge continued to delineate and improve the Company's reserve base through pool extensions, establishing new development fields, and new exploration/appraisal drilling throughout the year.

Surge took steps in 2024 to further strengthen its core area focus by divesting of non-core properties at Shaunavon, Valhalla, and Westrose, while also proactively reducing the number of booked undeveloped drilling locations in its remaining non-core properties. Surge's overall reserves and net asset value ("NAV") are now heavily weighted to its Sparky and SE Saskatchewan core areas.

With Surge's December 31, 2024 Reserve Report, the Company delivered the following:

- 90 million boe of Total Proved & Probable ("TPP") reserves, 85 percent of which are booked in the Sparky and SE Saskatchewan core areas;
- A Proved Developed Producing ("PDP") NAV⁵ of \$5.42 per basic share, a Total Proved ("TP") NAV of \$9.33 per basic share, and a TPP NAV of \$14.39 per basic share;
- Achieved a 94 percent organic PDP reserves replacement⁵ after taking into consideration the non-core asset sales completed in 2024;
 - Non-core asset dispositions in 2024 resulted in the sale of 4.1 million boe of PDP reserves, 17.0 million boe of TP reserves, and 23.6 million boe of TPP reserves as compared to 2023;

- Further increased the Company's allocation of future development capital ("FDC") towards Surge's Sparky and SE Saskatchewan core areas. On this basis, Management proactively removed 24.2 TP drilling locations (2.8 million boe of associated reserves⁵ and \$83 million of FDC) and 28.5 TPP drilling locations (4.3 million boe of associated reserves⁵ and \$100 million of FDC) that were previously booked in the Company's remaining non-core properties. This has further enhanced the weighting of the Company's reserves to its core areas, with 85 percent of 2024 reserves booked in Sparky and SE Saskatchewan.
- Achieved a 113 percent PDP organic reserves replacement⁵ in Surge's Sparky and SE Saskatchewan core areas (which now account for more than 95 percent of the Company's capital expenditures, and comprise approximately 90 percent of Surge's reserves);
- 409 gross (367.0 net) booked TPP drilling locations³, and 317 gross (284.0 net) TP drilling locations³; 90 percent of these booked drilling locations are located in the Company's Sparky and SE Saskatchewan core areas³;
- Liquids weighting of 91 percent (oil and natural gas liquids) in all reserve categories;
- Delivered a PDP Finding & Development ("F&D") cost of \$23.36/boe⁶;
 - 1.7x Recycle Ratio⁵ on a 2024 operating netback of \$39.40/boe (before realized losses on financial contracts); and
- Reported a strong reserve life index⁵ of 11.0 years on TPP reserves and 8.0 years on TP reserves.

2024 YEAR-END RESERVES DETAILS

The Company's reserves were independently evaluated by Sproule in accordance with National Instrument 51-101 –*Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), effective December 31, 2024. Surge's Annual Information Form (the "AIF") for the year ended December 31, 2024 contains Surge's reserves data and other oil and natural gas information as mandated by NI 51-101.

The following tables summarize Surge's 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 evaluated in the Sproule reserves report. The evaluation is based on Sproule's forecast pricing and exchange rates at December 31, 2024 which is available on their website www.sproule.com. All references to reserves in this release are to gross Company reserves, meaning Surge's working interest reserves before deductions of royalties and before consideration of the Company's royalty interests. The amounts in the tables may not add due to rounding.

RESERVES SUMMARY AND NET PRESENT VALUE

	Crude Oil and NGLs (Mbbbl) ^(b)	Natural Gas (MMcf) ^(c)	Oil Equivalent Total Reserves (Mboe)	Before Tax NPV of Future Net Revenue ^(d) Discounted at		
				5% (\$MM)	10% (\$MM)	15% (\$MM)
Gross Reserves^(a)						
Proved:						
Proved Producing	34,840	20,074	38,186	857	791	717
Proved Non-Producing	1,549	611	1,651	37	31	26
Proved Undeveloped	23,751	11,146	25,608	484	362	276
Total Proved	60,140	31,831	65,445	1,378	1,184	1,020
Probable	21,831	17,387	24,729	681	508	397
Total Proved Plus Probable	81,971	49,218	90,174	2,059	1,692	1,417

a) Amounts may not add due to rounding.

b) Includes light, medium, heavy and natural gas liquids.

c) Includes non-associated and natural gas, solution gas and coal bed methane.

Total ADR (Abandonment, Decommissioning, Reclamation) is included in the reserves report, as it is best practice as stated in the COGE Handbook.

FUTURE DEVELOPMENT CAPITAL ("FDC")

	Total Proved (\$MM)	Total Proved Plus Probable (\$MM)
2025	130	138
2026	143	164
2027	149	181
2028	99	165
2029	36	43
Remaining	24	34
Total (Undiscounted)	581	725
Total (Discounted at 10%)	472	577

F&D AND FD&A COSTS

	2024	3-Year Average
<u>F&D Costs, including total change in FDC^(a)</u>		
Proved Developed Producing	\$23.36	\$23.38
Total Proved	\$24.80	\$29.45
Total Proved + Probable	\$27.34	\$38.99
<u>FD&A Costs, including total change in FDC^(b)</u>		
Proved Developed Producing	\$36.20	\$24.50
Total Proved	N/A ^(c)	\$34.64
Total Proved + Probable	N/A ^(c)	\$58.11

a) 2024 F&D costs calculated using capital of \$195 million plus changes in FDC of -\$35 million (TP) and -\$33 million (TPP)
2024 FD&A costs calculated using capital of \$153 million plus changes in FDC of -\$279 million (TP) and -\$314 million

b) (TPP)

Not meaningful due to non-core dispositions; negative 2024 FD&A costs and negative reserve adds (-11 mmboe TP, -18

c) mmboe TPP).

NET ASSET VALUE

	PDP	TP	TPP
Reserve Value NPV10 BT (\$mm)	791	1,184	1,692
Net Debt (\$mm)	(247)	(247)	(247)
Total Net Assets (\$mm)	544	936	1,444
Basic Shares Outstanding (mm)	100.4	100.4	100.4
Estimated NAV per Basic Share (\$/share)	5.42	9.33	14.39

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As at December 31, 2024

Sproule Forecast ^(a) Year	Cushing, Oklahoma (\$US/bbl)	WTI	Canadian Light Sweet Crude 40° API		Western Canada Select (WCS) Crude 20.5 API		Natural Gas AECO-C Spot		Exchange Rate	
		(US\$/bbl)	(C\$/bbl)	(C\$/bbl)	(C\$/bbl)	(C\$/bbl)	(C\$/bbl)	(C\$/mmbtu)	(US\$/C\$)	(US\$/C\$)
	2024	2023	2024	2023	2024	2023	2024	2023	2024	2023
Forecast										
2025	\$71.00	\$76.00	\$97.14	\$97.33	\$83.57	\$81.33	\$2.29	\$2.33	0.700	0.750
2026	\$76.00	\$76.00	\$100.69	\$97.25	\$87.59	\$84.67	\$3.42	\$3.64	0.725	0.750
2027	\$76.00	\$76.00	\$97.33	\$97.17	\$84.67	\$84.33	\$3.31	\$3.95	0.750	0.750
2028	\$77.52	\$77.52	\$99.28	\$99.12	\$86.36	\$86.02	\$3.35	\$4.03	0.750	0.750
2029	\$79.07	\$79.07	\$101.27	\$101.10	\$88.09	\$87.74	\$3.41	\$4.11	0.750	0.750
2030	\$80.65	\$80.65	\$103.29	\$103.12	\$89.85	\$89.50	\$3.48	\$4.19	0.750	0.750
2031	\$82.26	\$82.26	\$105.36	\$105.18	\$91.65	\$91.29	\$3.55	\$4.27	0.750	0.750
2032	\$83.91	\$83.91	\$107.46	\$107.29	\$93.48	\$93.11	\$3.62	\$4.36	0.750	0.750
2033	\$85.59	\$85.59	\$109.61	\$109.43	\$95.35	\$94.97	\$3.69	\$4.44	0.750	0.750

2034	\$87.30	\$87.30	\$111.81	\$111.62	\$97.26	\$96.87	\$3.77	\$4.53	0.750	0.750
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a) Prices escalate at two percent after 2034, with the exception of foreign exchange which stays flat.

OUTLOOK: PREMIUM ASSET QUALITY DRIVES SUPERIOR RETURNS

In 2024 Surge generated \$294.1 million of AFF and FCF of \$99 million, representing 34 percent of the Company's 2024 AFF.

Surge is a publicly traded intermediate oil company focused on enhancing shareholder returns through free cash flow generation. The Company's defined operating strategy is based on owning and developing high quality, conventional light and medium gravity crude oil reservoirs, and using proven technology to enhance ultimate oil recoveries.

Surge has now assembled dominant operational positions in two of the top four crude oil plays in Canada¹ in its Sparky (>12,000 boepd; 90% medium gravity oil) and SE Saskatchewan (>8,000 boepd; 90% light oil) core areas. Over 90 percent of the Company's current production (and TPP NAV) now comes from these two core areas.

During the first half of 2025, Surge will continue to execute an active drilling program in both the Sparky and SE Saskatchewan core areas, with 17.2 net wells budgeted to be drilled.

Surge is well positioned to continue delivering attractive shareholder returns in 2025 and beyond based on the following key corporate fundamentals, utilizing the Company's 2025 budget pricing estimate of US\$70 WTI pricing per barrel⁶:

- Estimated 2025 average production of 22,500 boepd (91 percent liquids);
- Estimated 2025 AFF of \$275 million⁷;
- An estimated 2025 cash flow from operating activities of \$255 million⁶;
- A \$53 million annual base cash dividend (\$0.52 per share annual dividend, paid monthly);
- Surge's annual dividend represents only 19 percent of the Company's forecasted 2025 AFF of \$275 million;
- An estimated 25 percent annual corporate decline⁵;
- More than 900 (net) internally estimated drilling locations, providing a 12-year drilling inventory³;
- \$1.3 billion in tax pools (approximate 4 year tax horizon at US\$70 WTI pricing); and
- Total Proved plus Probable net asset value ("NAV") of \$14.39 per share and a Total Proved NAV of \$9.33 per share⁶.

FORWARD LOOKING STATEMENTS:

This press release contains forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements.

More particularly, this press release contains statements concerning: Surge's declared focus and primary goals; management's 2025 budgeted average production guidance; crude oil fixed price hedges protecting the Company's 2025 free cash flow profile; share repurchases under the Company's NCIB; the repeatability and consistency of drilling results at Hope Valley and moving this asset the full development phase; estimated Sparky drilling locations remaining on the Company's Hope Valley land and the future development of such land; Surge's planned 2025 drilling program and focus, including expectations regarding the number of wells to be drilled and the types thereof; Surge's 2025 capital program and focus; Surge's intention to have a dedicated rig drilling multi-lateral wells in Hope Valley for the entire year; Surge's expectations that wells drilled as part of its winter drilling program will be completed and on production in early Q2/25; Surge's reserves, future net revenue, future development capital and reserve life index; Surge continuing to execute an active drilling program at both the Sparky and SE Saskatchewan core areas during the first half of 2025 and the number of wells to be drilled thereat; management's belief that Surge is well positioned to deliver attractive shareholder returns; and management's expectations regarding Surge's 2025 average production, AFF, cash flow from operating activities, dividends, drilling inventory and locations, annual corporate decline rates, tax pools and tax horizon.

The forward-looking statements are based on certain key expectations and assumptions made by Surge, including expectations and assumptions the performance of existing wells and success obtained in drilling new wells; anticipated expenses, cash flow and capital expenditures; the application of regulatory and royalty regimes; prevailing commodity prices and economic conditions; development and completion activities; the performance of new wells; the successful implementation of waterflood programs; the availability of and performance of facilities and pipelines; the geological characteristics of Surge's properties; the successful application of drilling, completion and seismic technology; the determination of decommissioning liabilities; prevailing weather conditions; exchange rates; licensing requirements; the impact of completed facilities on operating costs; the availability

and costs of capital, labour and services; and the creditworthiness of industry partners.

Although Surge believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Surge can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the condition of the global economy, including trade, public health (including the impact of COVID-19) and other geopolitical risks; risks associated with the oil and gas industry in general (e.g. operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks); commodity price and exchange rate fluctuations and constraint in the availability of services, adverse weather or break-up conditions; the imposition or expansion of tariffs imposed by domestic and foreign governments or the imposition of other restrictive trade measures, retaliatory or countermeasures implemented by such governments, including the introduction of regulatory barriers to trade and the potential effect on the demand and/or market price for Surge's products and/or otherwise adversely affects Surge; uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures; and failure to obtain the continued support of the lenders under Surge's bank line. Certain of these risks are set out in more detail in Surge's AIF dated March 5, 2025 and in Surge's MD&A for the period ended December 31, 2024, both of which have been filed on SEDAR+ and can be accessed at www.sedarplus.ca.

The forward-looking statements contained in this press release are made as of the date hereof and Surge undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Oil and Gas Advisories

Barrel of Oil Equivalency

The term "boe" means barrel of oil equivalent on the basis of 1 boe to 6,000 cubic feet of natural gas. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6,000 cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. "Boe/d" and "boepd" mean barrel of oil equivalent per day. Bbl means barrel of oil and "bopd" means barrels of oil per day. NGLs means natural gas liquids.

Oil and Gas Metrics

This press release contains certain oil and gas metrics and defined terms which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar metrics/terms presented by other issuers and may differ by definition and application. All oil and gas metrics/terms used in this document are defined below:

"Acquisition capital" is a non-GAAP financial measure used in the determination of FD&A costs, which is a non-GAAP ratio. The most directly comparable GAAP measure to acquisition capital is expenditures on acquisitions. For property acquisitions and dispositions, acquisition capital is the net purchase price of assets acquired (and net proceeds of assets disposed). For corporate acquisitions, it is the purchase price (cash and/or shares plus assumed bank debt, if applicable) including any estimated working capital surplus or deficit rather than the amounts allocated to property, plant and equipment for accounting purposes. The following table details the calculation of Acquisition capital for the periods indicated:

	Years Ended December 31,		
(\$000s)	2024	2023	2022
Expenditures on acquisitions	3,535	4,240	200,302
Less: cash from dispositions	(45,924)	(2,570)	(32)
Acquisition capital	(42,389)	1,670	200,270

"Capital payout" or "payout per well", is the time period for the operating netback of a well to equate to the individual cost of drilling, completing and equipping the well. Management uses capital payout and payout per well as a measure of capital efficiency of a well to make capital allocation decisions.

"Development capital" is used in the determination of FD&A costs, which is a non-GAAP ratio. Development capital is the Company's expenditures on property, plant, and equipment. Development capital means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development.

"Original oil in place (OOIP)" refers to the initial volume of oil present in the reservoir at the time of its formation.

"PDP F&D (Finding & Development)" is calculated on the Capital spent for 2024 development of all properties (other than those Acquired or Disposed of in 2024), divided by the sum of all reserve additions other than those from Acquisitions &

Dispositions. Development capital is a component of F&D. Management uses F&D as a measure of capital efficiency for organic reserves development.

"Finding, Development and Acquisition (FD&A)" is the sum of the Capital spent for 2024 development including Acquisition & Divestiture properties, plus 2024 total Acquisition & Disposition capital, plus the delta on Future Development Costs (from 2023YE vs 2024YE), divided by the sum of all reserve additions including those from Acquisitions & Dispositions. Acquisition capital is a non-GAAP financial measure used as a component of FD&A costs. Management uses FD&A costs as a measure of capital efficiency for organic and acquired reserves development.

"Recycle ratio" is calculated by dividing operating netback per boe by F&D costs for the year. Operating netback per boe is a non-GAAP ratio that uses operating netback, a non-GAAP financial measure, as a component. Acquisition capital, a non-GAAP financial measure, is used as a component of F&D costs. Management uses the recycle ratio to relate the cost of adding reserves to the expected cash flows to be generated.

"Net Asset Value (NAV)" is calculated as reserve value discounted at 10% on a BTax basis, less the Company's net debt, a non-GAAP financial measure, at December 31, 2024 of \$247.1 million and is divided by 100.4 million common shares outstanding as at December 31, 2024. **"Reserve Life Index"** is calculated as total Company share reserves divided by Surge's estimated average 2025 production (22,500 boepd).

"Reserve Life Index" is calculated as total Company share reserves divided by Surge's estimated average 2025 production (22,500 boepd).

"Reserves Replacement Ratio" is the ratio of reserves booked through acquisitions, dispositions, discoveries, infills, extensions, economic factors, technical revisions, and improved recovery to production for the period.

"Organic Reserves Replacement Ratio" is the reserves replacement ratio excluding the effect of acquisitions and dispositions.

"Decline" is the amount existing production decreases year over year, without new drilling. Sproule's 2024YE reserves have a PDP decline of 27 percent and a P+PDP decline of 25 percent.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare our operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Drilling Inventory

This press release discloses drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved locations and probable locations derived from an external evaluation using standard practices as prescribed in the Canadian Oil and Gas Evaluations Handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable.

Unbooked locations are internal estimates based on prospective acreage and assumptions as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by Surge's internal certified Engineers and Geologists (who are also Qualified Reserve Evaluators) as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where Management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Assuming a January 1, 2025 reference date, the Company will have over >975 gross (>900 net) drilling locations identified herein; of these >575 gross (>525 net) are unbooked locations. Of the 367 net booked locations identified herein, 284 net are Proved locations and 83 net are Probable locations based on Sproule's 2024YE reserves. Assuming an average number of net wells drilled per year of 75, Surge's >900 net locations provide 12 years of drilling.

Assuming a January 1, 2025 reference date, the Company will have over >500 gross (>475 net) Sparky Core area drilling locations identified herein; of these >300 gross (>300 net) are unbooked locations. Of the 196 net booked locations identified herein, 143 net are Proved locations and 53 net are Probable locations based on Sproule's 2024YE reserves. Assuming an average number of wells drilled per year of 40, Surge's >475 net locations provide >12 years of drilling.

Assuming a January 1, 2025 reference date, the Company will have over >80 gross (>80 net) Sparky Hope Valley area drilling

locations identified herein; of these >60 gross (>60 net) are unbooked locations. Of the 22 net booked locations identified herein, 17 net are Proved locations and 5 net are Probable locations based on Sproule's 2024YE reserves.

Assuming a January 1, 2025 reference date, the Company will have over >325 gross (>275 net) SE Saskatchewan drilling locations identified herein; of these >170 gross (>145 net) are unbooked locations. Of the 145 net booked locations identified herein, 115 net are Proved locations and 30 net are Probable locations based on Sproule's 2024YE reserves. Assuming an average number of wells drilled per year of 35, Surge's >275 net locations provide >8 years of drilling.

Surge's internally used type curves were constructed using a representative, factual and balanced analog data set, as of January 1, 2024. All locations were risked appropriately, and EUR's were measured against OOIP estimates to ensure a reasonable recovery factor was being achieved based on the respective spacing assumption. Other assumptions, such as capital, operating expenses, wellhead offsets, land encumbrances, working interests and NGL yields were all reviewed, updated and accounted for on a well-by-well basis by Surge's Qualifies Reserve Evaluators. All type curves fully comply with Part 5.8 of the Companion Policy 51 – 101CP.

Surge's internal Hope Valley type curve profile of 172 bopd (IP30), 168 bopd (IP90) and 175 mbbbl (175 mboe) EUR reserves per well, with assumed \$2.5 MM per well capital, has a payout of ~10 months @US\$70/bbl WTI (C\$93.05/bbl LSB) and a ~175% IRR.

Non-GAAP and Other Financial Measures

This press release includes references to non-GAAP and other financial measures used by the Company to evaluate its financial performance, financial position or cash flow. These specified financial measures include non-GAAP financial measures and non-GAAP ratios and are not defined by IFRS, and therefore are referred to as non-GAAP and other financial measures. Certain secondary financial measures in this press release are not prescribed by GAAP. These non-GAAP and other financial measures are included because Management uses the information to analyze business performance, cash flow generated from the business, leverage and liquidity, resulting from the Company's principal business activities and it may be useful to investors on the same basis. None of these measures are used to enhance the Company's reported financial performance or position. The non-GAAP and other financial measures do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP and other financial measures used in this document are defined below, and as applicable, reconciliations to the most directly comparable GAAP measure for the quarter and year ended December 31, 2024, have been provided to demonstrate the calculation of these measures:

Acquisition Capital, FD&A Costs & Recycle Ratio

Acquisition capital is a non-GAAP financial measure and FD&A costs and recycle ratio are non-GAAP ratios. See "Oil and Gas Advisories".

Adjusted Funds Flow & Adjusted Funds Flow Per Share

Adjusted funds flow is a non-GAAP financial measure. The Company adjusts cash flow from operating activities in calculating adjusted funds flow for changes in non-cash working capital, decommissioning expenditures, and cash settled transaction and other costs. Management believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such may not be useful for evaluating Surge's cash flows.

Changes in non-cash working capital are a result of the timing of cash flows related to accounts receivable and accounts payable, which management believes reduces comparability between periods. Management views decommissioning expenditures predominately as a discretionary allocation of capital, with flexibility to determine the size and timing of decommissioning programs to achieve greater capital efficiencies and as such, costs may vary between periods. Transaction and other costs represent expenditures associated with property acquisitions and dispositions, debt restructuring and employee severance costs, which management believes do not reflect the ongoing cash flows of the business, and as such reduces comparability. Each of these expenditures, due to their nature, are not considered principal business activities and vary between periods, which management believes reduces comparability.

Adjusted funds flow per share is a non-GAAP ratio, calculated using the same weighted average basic and diluted shares used in calculating income (loss) per share.

The following table reconciles cash flow from operating activities to adjusted funds flow and adjusted funds flow per share:

	Three Months Ended December 31, Years Ended December 31,			
(\$000s except per share)	2024	2023	2024	2023
Cash flow from operating activities	64,838	79,712	278,647	266,141
Change in non-cash working capital	5,303	(11,261)	(7,191)	9,350
Decommissioning expenditures	5,535	8,255	15,175	15,560

Cash settled transaction and other costs	445	295	7,492	795
Adjusted funds flow	76,121	77,001	294,123	291,846
Per share - basic (\$)	\$0.75	\$0.77	\$2.92	\$2.95

Free Cash Flow

Free cash flow and excess free cash flow are non-GAAP financial measures. During the year ended December 31, 2024, Management changed the composition of free cash flow and excess free cash flow. This change was made as a result of Management's assessment that decommissioning expenditures and cash settled transaction and other costs are not considered principal business activities and vary between periods, which Management believes reduces comparability. Management believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such, may not be useful for evaluating Surge's cash flows. Prior period calculations of free cash flow have been restated in the table below to reflect this change.

Free cash flow is calculated as cash flow from operating activities, adjusted for changes in non-cash working capital, decommissioning expenditures, and cash settled transaction and other costs, less expenditures on property, plant and equipment. Excess free cash flow is calculated as cash flow from operating activities, adjusted for changes in non-cash working capital, decommissioning expenditures, and cash settled transaction and other costs, less expenditures on property, plant and equipment, and dividends paid. Management uses free cash flow and excess free cash flow to determine the amount of funds available to the Company for future capital allocation decisions.

	Three Months Ended December 31, Years Ended December 31,			
<i>(\$000s)</i>	2024	2023	2024	2023
Cash flow from operating activities	64,838	79,712	278,647	266,141
Change in non-cash working capital	5,303	(11,261)	(7,191)	9,350
Decommissioning expenditures	5,535	8,255	15,175	15,560
Cash settled transaction and other costs	445	295	7,492	795
Adjusted funds flow	76,121	77,001	294,123	291,846
Less: expenditures on property, plant and equipment	(58,277)	(61,305)	(195,103)	(181,572)
Free cash flow	17,844	15,696	99,020	110,274
Less: dividends paid	(13,150)	(12,037)	(50,020)	(46,822)
Excess free cash flow	4,694	3,659	49,000	63,452

Net Debt

Net debt is a non-GAAP financial measure, calculated as bank debt, term debt, plus the liability component of the convertible debentures plus current assets, less current liabilities, however, excluding the fair value of financial contracts, decommissioning obligations, and lease and other obligations. There is no comparable measure in accordance with IFRS for net debt. This metric is used by management to analyze the level of debt in the Company including the impact of working capital, which varies with the timing of settlement of these balances.

<i>(\$000s)</i>	As at Dec 31, 2024	As at Sep 30, 2024	As at Dec 31, 2023
Cash	7,594	11,500	—
Accounts receivable	58,327	53,193	53,354
Prepaid expenses and deposits	3,233	4,215	5,355
Accounts payable and accrued liabilities	(95,433)	(93,094)	(85,390)
Dividends payable	(4,350)	(4,395)	(4,013)
Bank debt	—	—	(42,797)
Senior unsecured notes	(170,872)	(170,642)	—
Term debt	(6,224)	(9,094)	(178,731)
Convertible debentures	(39,401)	(38,997)	(37,848)
Net Debt	(247,126)	(247,314)	(290,070)

Net Operating Expenses & Net Operating Expenses per boe

Net operating expenses is a non-GAAP financial measure, determined by deducting processing income, primarily generated by processing third party volumes at processing facilities where the Company has an ownership interest. It is common in the industry to earn third party processing revenue on facilities where the entity has a working interest in the infrastructure asset. Under IFRS this source of funds is required to be reported as revenue. However, the Company's principal business is not that of a midstream entity whose activities are dedicated to earning processing and other infrastructure payments. Where the Company has excess capacity at one of its facilities, it will look to process third party volumes as a means to reduce the cost of operating/owning the facility. As such, third party processing revenue is netted against operating costs when analyzed by

management. Net operating expenses per boe is a non-GAAP ratio, calculated as net operating expenses divided by total barrels of oil equivalent produced during a specific period of time.

	Three Months Ended December 31, Years Ended December 31,			
<i>(\$000s)</i>	2024	2023	2024	2023
Operating expenses	44,563	47,602	185,638	196,256
Less: processing income	(1,780)	(1,734)	(8,592)	(7,780)
Net operating expenses	42,783	45,868	177,046	188,476
Net operating expenses (\$ per boe)	19.12	19.90	20.02	21.13

Operating Netback, Operating Netback per boe, and Adjusted Funds Flow per boe

Operating netback is a non-GAAP financial measure, calculated as petroleum and natural gas revenue and processing and other income, less royalties, realized gain (loss) on commodity and FX contracts, operating expenses, and transportation expenses. Operating netback per boe is a non-GAAP ratio, calculated as operating netback divided by total barrels of oil equivalent produced during a specific period of time. There is no comparable measure in accordance with IFRS. This metric is used by management to evaluate the Company's ability to generate cash margin on a unit of production basis.

Adjusted funds flow per boe is a non-GAAP ratio, calculated as adjusted funds flow divided by total barrels of oil equivalent produced during a specific period of time.

Operating Netback & Adjusted Funds Flow are Calculated on a per unit basis as follows:

	Three Months Ended December 31, Years Ended December 31,			
<i>(\$000s)</i>	2024	2023	2024	2023
Petroleum and natural gas revenue	163,172	168,453	656,703	670,375
Processing and other income	1,780	1,734	8,592	7,780
Royalties	(29,693)	(31,235)	(119,919)	(119,513)
Realized gain (loss) on commodity and FX contracts	(264)	2,351	(3,493)	(3,164)
Operating expenses	(44,563)	(47,602)	(185,638)	(196,256)
Transportation expenses	(3,101)	(3,411)	(11,429)	(13,755)
Operating netback	87,331	90,290	344,816	345,467
G&A expense	(5,216)	(5,041)	(20,653)	(19,158)
Interest expense	(5,994)	(8,248)	(30,040)	(34,463)
Adjusted funds flow	76,121	77,001	294,123	291,846
Barrels of oil equivalent (boe)	2,237,273	2,304,615	8,841,938	8,920,018
Operating netback (\$ per boe)	39.03	39.18	39.00	38.73
Adjusted funds flow (\$ per boe)	34.02	33.41	33.26	32.72

Neither the TSX nor its Regulation Services Provider (as that term is defined in the policies of the TSX) accepts responsibility for the adequacy or accuracy of this release.

¹ Source: Peters & Co. January 16, 2025 North American Crude Oil and Natural Gas Plays.

² This is a non-GAAP and other financial measure which is defined under Non-GAAP and Other Financial Measures.

³ See Drilling Inventory.

⁴ Per GeoScout data for all SE Saskatchewan Frobisher wells with an on-production date from January 1, 2022 to December 31, 2024 and 90 days of production data available.

⁵ This adjustment is included in the technical revisions category within the Reconciliation of Changes in Reserves table in the Company's December 31, 2024 AIF.

⁶ See Oil and Gas Advisories.



For further information: FURTHER INFORMATION: For more information, please contact: Paul Colborne, President & CEO, Surge Energy Inc., Phone: (403) 930-1507, Email: pcolborne@surgeenergy.ca; Jared Ducs, Chief Financial Officer, Surge Energy Inc., Phone: (403) 930-1046, Email: jducs@surgeenergy.ca

<https://surgeenergy.mediaroom.com/2025-03-05-SURGE-ENERGY-INC-ANNOUNCES-FOURTH-QUARTER-AND-YEAR-END-FINANCIAL-RESULTS-FOR-2024-2024-YEAR-END-RESERVES-AND-OPERATIONAL-UPDATES>