Susitna Valley Natural Gas
Conceptual Development Plan Proposal
Southcentral Alaska

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Prepared for

Denali Petroleum and Gas Company
645 G Street, Suite 732
Anchorage, AK, 99501

Prepared by

ASRC CONSULTING & ENVIRONMENTAL
AN ASRC ENERGY COMPANY
3900 C Street, Suite 701
Anchorage, Alaska 99503

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Acronyms and Abbreviations

2D	two-dimensional
ac	acre
ACES	ASRC Consulting & Environmental Services, LLC
ADNR	Alaska Department of Natural Resources
AOGCC	Alaska Oil and Gas Conservation
ASRC	Arctic Slope Regional Corporation
AU	assessment unit
Avg SW	average water saturation (fraction)
bbl	barrel(s))
bcf	billion standard cubic feet
BHL	bottom hole location
bpd	barrels per day
Btu	British thermal unit
bwpd	barrels of water per day
Capex	capital expenditure
CBM	coal bed methane
CH	cased-hole completion
D&C	drilling and completion
DEC	Alaska Department of Environmental Conservation
e-line	electric line
ENSTAR	ENSTAR Natural Gas Company
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement, and construction
ESP	electric submersible pump
FEED	front-end engineering design
FID	final investment decision
ft	feet
GAC	granular activated carbon
GIP	gas in place
Grant Lake	Grant Lake Corporation
GWR	gas–water ratio (scf/bbl)
Hilcorp	Hilcorp Energy Company
hr	hour
IGIP	initial gas in place
IRR	internal rate of return
LWD	logging-while-drilling
md	millidarcy
Mmscf	million standard cubic feet

MNR	magnetic nuclear resonance
MOB	mobilization
Mscf	thousand standard cubic feet
MWD	measurement while drilling
NPV	net present value
NRM	natural remanent magnetization
NuTech	NuTech Energy Alliance
OH	open-hole completion
Opex	operating expenditure
OSY	OSY Oilfield Services Ltd.
P&A	plug and abandonment
PCP	progressing cavity pump
PERM	permeability
PHIE	effective porosity (fraction)
ppm	parts per million
RO	reverse osmosis
SBM	sand-bed methane
SCAL	special core analysis
scf/ton	standard cubic feet per ton
Tcf	trillion standard cubic feet
TD	total depth
TG	toll gate
TVD	true vertical depth (ft)
TVT	true vertical thickness (ft)
U/D	upthrown and downthrown (sides of a fault)
USD	U.S. dollar
USGS	U.S. Geological Survey
Well No. 3	Appraisal well targeting CBM in the shallow fault block
Well No. 1	Appraisal well targeting SBM and shallow free gas
Well No. 2	Appraisal well targeting deep CBM and free gas
WFU	Water Filtration Unit

1.0 EXECUTIVE SUMMARY

The attached plan is a phased approach to assess the long-term commercial viability of natural gas production for utility use in Southcentral Alaska. The lower Susitna Valley, north of the Castle Mountain Fault, is rich in coal seams, as evidenced by earlier exploration oil wells, and contains multiple gas resource: sand bed methane (SBM), coal bed methane (CBM), and conventional trapped gas.

Estimated gas resources from the 567,000 acres made available by the Alaska Department of Natural Resources in August 2025 are as follows:

- **Sand Bed Methane (SBM):** ~153.2 trillion cubic feet (Tcf) (Assessment by Gary Player 2024)
- **Coal Bed Methane (CBM):** ~2.4 Tcf (Assessment by ASRC CONSULTING AND ENVIRONMENTAL SERVICES 2025)
- **Conventional Trapped Gas:** ~1.7 Tcf (*Assessment of Undiscovered Oil and Gas Resources of the Cook Inlet–Susitna Region, Alaska*) [Stanley et al. 2018])

The multi-well proposed appraisal plan consists of evaluating each of these gas resources through long-term testing, full formation evaluation, coring, and subsequent laboratory analysis. Specifically, three wells are currently planned:

- Well No. 1: Test SBM and conventional trapped gas resources
- Well No. 2: Test CBM and conventional trapped gas resources
- Well No. 3: Evaluate CBM and SBM gas resources
- Estimated total cost is approximately $155 million dollars.

Full field development economics are projected to provide internal rates of returns above the commercially acceptable limits in all the possible success cases post appraisal program; sand bed methane only development, coal bed methane only development, and trapped free gas plays in the lease area.

Conceptual SBM and CBM developments economic returns could be substantially improved with a strategic drilling services procurement plan targeting total development well costs of $1.5 to 2.0 million per well. This approach would include evaluating the purchase of rigs that are operated and maintained by a qualified subcontractor. Investment risk is minimized through a staged approach that evaluates each gas resource and incorporates the design and procurement of project-specific separation facilities. Overall objectives should include reducing reservoir and drilling risks while maintaining competitive costs and production efficiencies.

2.0 CURRENT SOUTHCENTRAL ALASKA GAS SUPPLY

Hilcorp Energy Company (Hilcorp) is the dominant energy supplier for more than half the state's population, providing around 85 percent of the gas that heats and powers homes and businesses across much of Alaska. Key conditions affecting the current and future gas supply in Southcentral Alaska include the following:

- Existing gas supply contracts are scheduled for renewal in the next two to nine years.

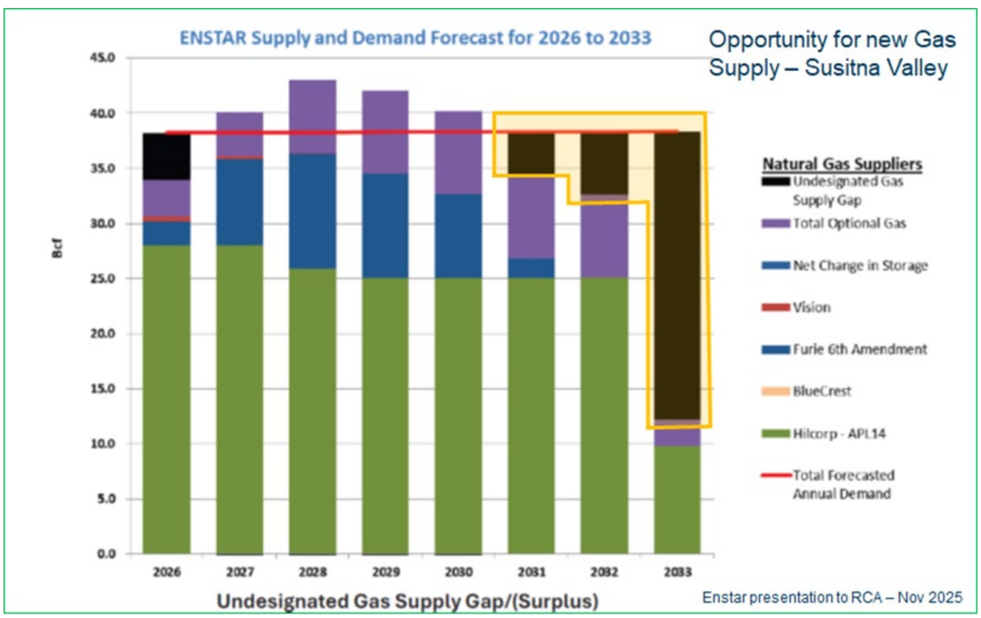
  Hilcorp does not currently have sufficient natural gas reserves in Cook Inlet to support new gas contracts and has not committed to investing in future gas development in Cook Inlet.

- Denali Petroleum and Gas, LLC (Denali) has had discussions with numerous utilities to negotiate long-term contracts to supply 35–45 billion standard cubic feet (bcf)/year.

- Six of the largest utilities in Alaska have formed a new group to identify additional natural gas resources and to reduce reliance on a single supplier (i.e., Hilcorp).

Figure 2-1 shows the gas supply and demand for ENSTAR through the year 2033. The highlighted columns in the years 2031 through 2033 show a deficit between supply and demand, noted as an undesignated gas supply gap. This creates a favorable market condition for a new gas source in the Susitna Valley to fill this gap.

Figure 2-1 ENSTAR Supply and Demand



Key: ENSTAR = ENSTAR Natural Gas Company RCA = Regulatory Commission of Alaska

Note: The Susitna Valley offers potential new gas supply through sand-bed methane (SBM), coal bed methane (CBM), and conventional trapped gas plays.

3.0 REGIONAL GEOLOGY – COOK INLET AND SUSITNA VALLEY

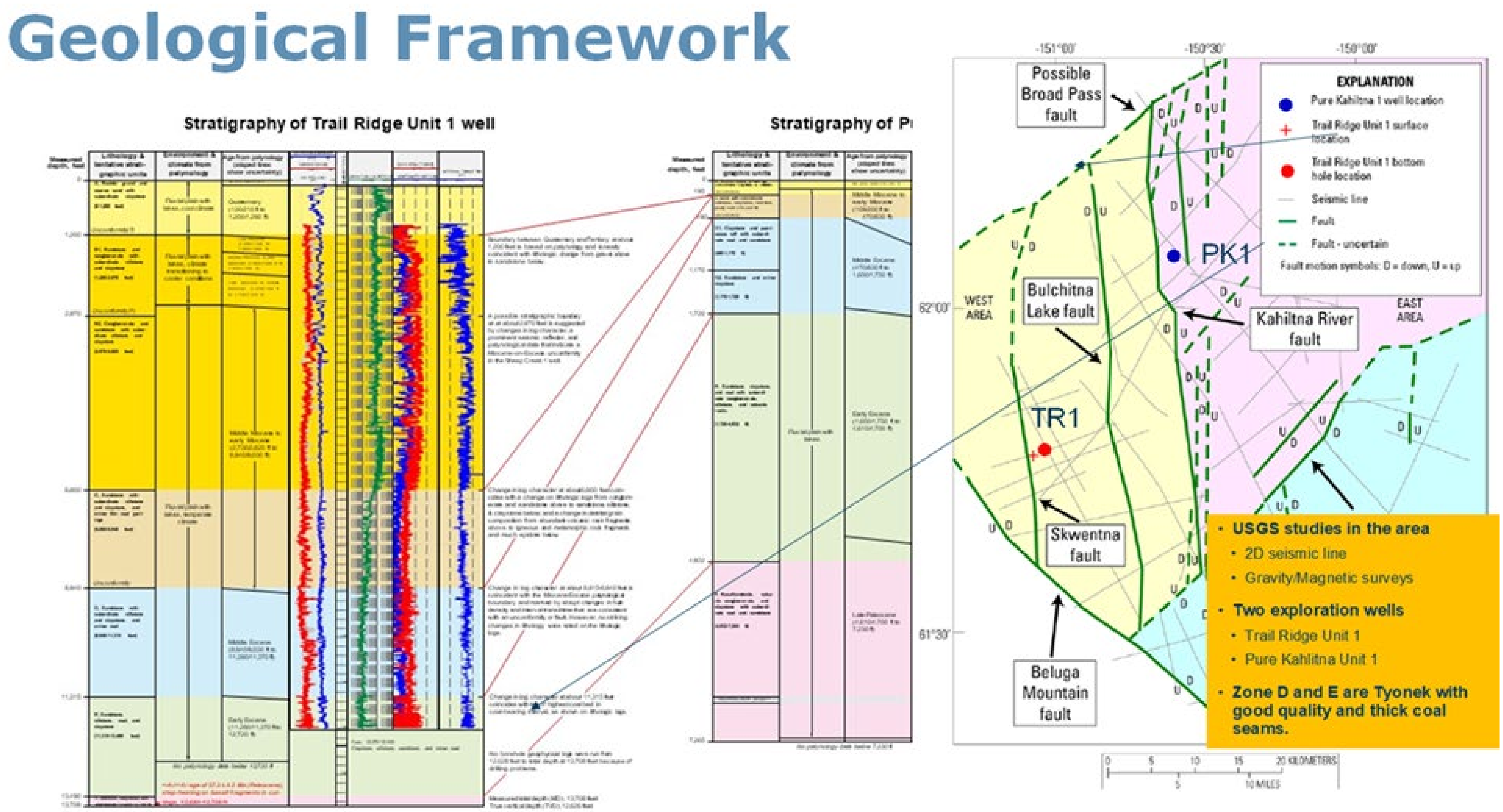
The U.S. Geological Survey (USGS) has assessed undiscovered, technically recoverable coalbed gas resources in the Cook Inlet–Susitna region of Southcentral Alaska (2012). The study area spans approximately 9.6 million acres and includes the Cook Inlet Basin, Matanuska Valley, and Susitna lowland. Coal beds, serving as both source and reservoir rocks, were deposited during the Paleocene through the Pliocene epochs in fluvial systems. Individual coal beds range from a few inches to more than 50 feet thick, with cumulative thickness exceeding 800 feet in some areas. Coal rank varies from lignite to subbituminous, and most coals are thermally immature, suggesting biogenic gas origin.

Specifically, the Susitna basin, located approximately 50 miles north of Anchorage, Alaska, is a largely unexplored region with no current commercial oil or gas production. The USGS conducted its first detailed assessment of the basin’s undiscovered, technically recoverable petroleum resources using a geology-based methodology (Stanley et al. 2018). This assessment was prompted by growing interest in natural gas supplies for the Anchorage metropolitan area, where natural gas is the primary source of energy for heating and electricity. The study highlights approximately 1.7 Tcf of potentially recoverable gas in the Susitna Valley.

Geophysical investigations of the Susitna basin reveal an asymmetric structure with sedimentary fill exceeding four kilometers in thickness in its western sector, bounded by steep reverse faults and trending folds. These structural features, formed during the Eocene through the Miocene epochs and modified by later tectonic activity, reflect the influence of Yakutat microplate subduction and regional strain partitioning. The basin's morphology, characterized by fault segmentation and uplift patterns, suggests complex deformation but does not preclude hydrocarbon development. Integration of gravity, magnetic, and seismic data confirms substantial sedimentary sequences and highlights areas of potential resource concentration.

Refer to Appendix A for detailed USGS reports on Cook Inlet and Susitna Valley. Figure 3-1 shows a USGS geological study which highlights the stratigraphic framework in the Susitna Valley, and a representation of major faults from the 2D survey (circa 1980).

Figure 3-1 Geological Framework for the Susitna Valley, Faults, and Depositional System



4.0 LEASE AREA DESCRIPTION

The Susitna Valley Gas Exploration licenses cover approximately 567,359 acres, divided into two areas: License Area 1 (263,983 acres) and License Area 2 (303,376 acres) (ADNR 2025). These areas are located west of the George Parks Highway in the Susitna River basin within the Matanuska-Susitna Borough. Boundaries were adjusted to exclude the Susitna River and private lands to minimize conflicts and environmental impacts. The southwest portion of License Area 1 was reduced due to the Beluga Fault, and the western portion of License Area 2 was excluded due to low petroleum potential and proximity to Skwentna. Approximately 71 percent of the surface estate is state-owned, with the remainder privately owned or managed by municipalities and trusts. Access is primarily via secondary roads, trails, and airstrips, with some areas accessible only by helicopter or floatplane.

4.1 Geographic and Environmental Features

The Susitna Valley is bounded by the Alaska Range, Talkeetna Mountains, and Chugach Mountains. The license areas include boreal forests, wetlands, rivers, and lakes that support diverse wildlife and fish populations. Natural hazards include earthquakes, flooding, erosion, wildfires, and permafrost. The climate is transitional between maritime and continental, with long, cold winters and mild summers.

4.2 Petroleum Potential

The Susitna basin has low-to-moderate potential for conventional and unconventional gas resources, primarily coal bed methane. A 2017 USGS assessment estimated 1.7 trillion cubic feet (Tcf) of undiscovered microbial gas resources (Stanley et al. 2018). Exploration history includes several dry wells, and no current production exists. If coal bed methane becomes economically viable, it could provide an alternative energy source for rural communities and support carbon sequestration initiatives.

Table 4-1 summarizes the area and elevations, as well as exploration wells in the two lease areas.

Table 4-1 License Area Definition and Characteristics

License Area	Acreage (thousand acres)	Elevation Range (ft)	Median Elevation (ft)	Legacy Wells / Notes
License Area 1	263	48–418	147	Pure Kahiltna Unit 1 (1964) – TD 7,265 ft; P&A 03/11/1964
License Area 2	303	93–1,094	365	Trail Ridge Unit 1 (1980–82) – TD 13,708 ft; cores below 12,000’ showed siltstones; P&A 08/28/1982

5.0 ESTIMATES OF INITIAL GAS IN PLACE

Three sources of initial gas in place (IGIP) estimates are summarized in Sections 5.1 through 5.3 of this report. ASRC Consulting & Environmental Services, LLC (ASRC CONSULTING AND ENVIRONMENTAL SERVICES) is not in a position to validate the methods or studies described in Sections 5.1 and 5.2 and has therefore performed its own evaluation based on known historical data and studies (described in Section 5.3). All methods indicate significant upside to gas prospects in the Susitna Valley.

5.1 Denali P&G - Dissolved Gas in Sand Bed Methane

Gary F. Player, a registered geologist with a long history in this region, conducted studies of the Susitna Valley basin in 2024. Although unpublished, these reports were provided to Denali P&G and include estimates of the volume of potential resources in the sand bed methane (SBM).

Based on Gary Player's assessment, the Susitna basin presents a significant opportunity to address Alaska's growing energy needs through the development of dissolved gas resources in deep saline aquifers. Recent studies estimate that the basin contains approximately 136 Tcf of natural gas dissolved in formation water, distributed across an area of nearly 500,000 acres with substantial sand thickness and high porosity. This resource can be produced without hydraulic fracturing, using environmentally responsible methods that reinject water to maintain reservoir pressure and prevent subsidence.

Based on Player's assessment, the Susitna basin dissolved gas prospect represents a transformative opportunity for Alaska's energy security. Its vast resource base, favorable extraction conditions, and proximity to existing infrastructure position it as a strategic priority for early investment. Development of this resource will not only stabilize regional energy supply but also deliver long-term economic benefits while minimizing environmental impact. Appendix B summarizes the documents provided by Gary Player in support of the initial estimates of gas in place.

Player's estimates of dissolved gas in place resources indicated 173 bcf per 640-acre section and up to 250.3 Tcf for the entire Susitna Valley. With the updated lease area (ADNR 2025), this translates to 153.2 Tcf for the reduced acreage.

5.2 USGS– Coal Bed Methane and Conventional Gas in Sandstone Reservoirs in Cook Inlet and Susitna Valley

The USGS performed two studies in the region. The first study focused on geology and potential resources in coal bed methane (CBM) in the entire Cook Inlet and Susitna Valley and is included in Appendix A (Scientific Investigation Report 2012-5145 [Rouse and Houseknecht 2012]). The second study focused on conventional gas and petroleum system in Susitna Valley basin, included in Appendix A (Stanley et al. 2018).

From the Rouse and Houseknecht study (2012), the assessment unit (AU) is hypothetical due to limited well testing; analog data from the Powder River basin were used for resource estimation. The mean estimate of undiscovered coal bed gas resources is 4.674 Tcf, with a range from 1.581 Tcf (F95) to 10.069 TCF (F5). Potential for reserve additions in the next 30 years is greatest along the western Cook Inlet basin where coal thickness is highest.

Potential source rocks include organic-rich coals and shales, while reservoirs are expected in sandstones and conglomerates within structural and stratigraphic traps. The analysis incorporated geological field data, exploration wells, seismic surveys, and geophysical studies.

Results indicate that the Susitna Valley contains modest but significant natural gas resources and limited oil potential. The estimated undiscovered natural gas resources range from zero to 4,672 billion cubic feet (bcf), with a mean of 1,679 bcf, nearly all of which is expected in the Susitna Tertiary Sandstone.

These findings suggest that while oil prospects are minimal, Susitna Valley could provide an important source of natural gas for the Anchorage region, supporting energy security and reducing reliance on other supply sources. Appendix A summarizes the USGS estimates of gas in place in Cook inlet and Susitna Valley.

5.3 ASRC CONSULTING AND ENVIRONMENTAL SERVICES Assessment of Gas in Place in Susitna Valley lease area

ASRC CONSULTING AND ENVIRONMENTAL SERVICES performed an independent review of the USGS studies in the area, as well as a review of 2D seismic geological framework in the Susitna Valley basin to estimate the potential gas resources in SBM, CBM. and conventional gas that could be structurally trapped and provide a significant upside to future development in this basin.

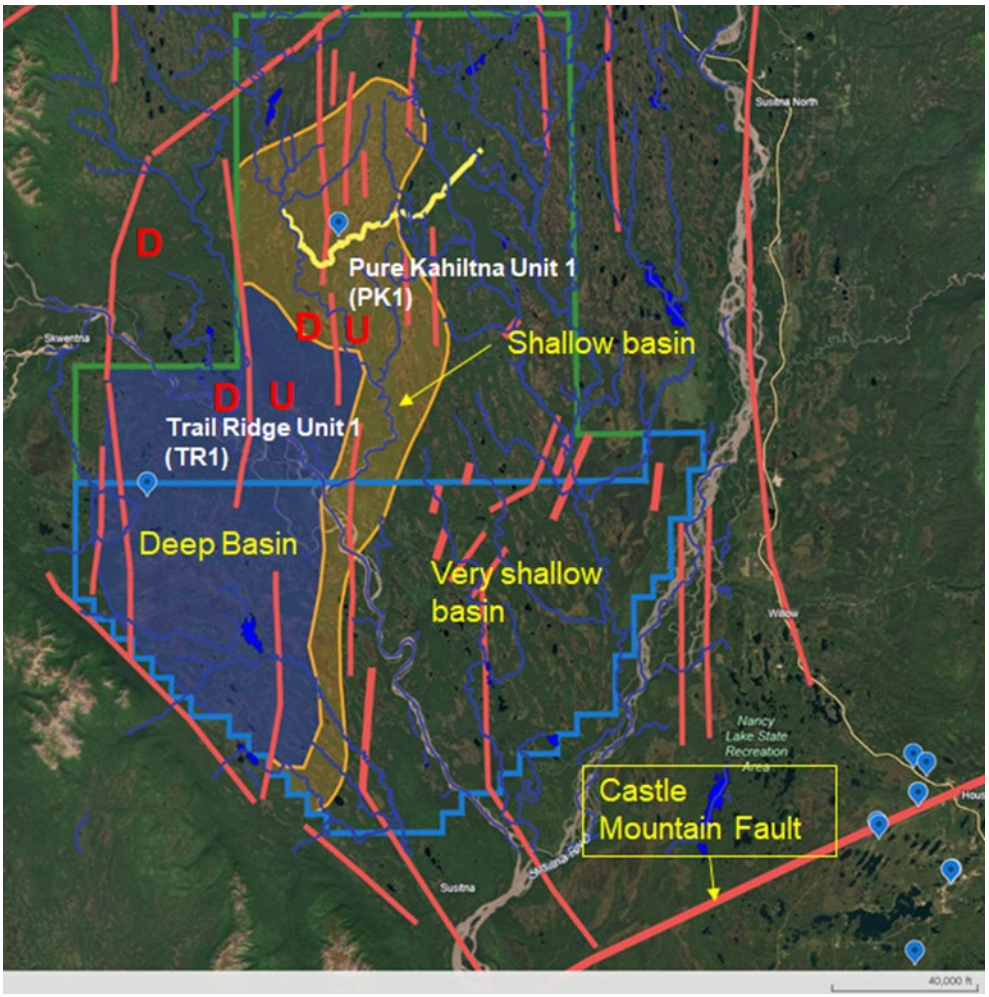
The Susitna basin is separated from the Cook Inlet Basin by the Castle Mountain Fault. It is a deep basin, reaching depths of up to approximately 15,000 feet, and is sourced from the Alaska Range, Talkeetna Mountains, and Tordrillo Mountains. The following summaries describe the stratigraphy and reservoir characteristics observed in the two legacy exploration wells:

- **Trail Ridge Unit 1**: Approximately 9,000 feet of equivalent Kenai Group (Sterling, Beluga, Tyonek) non-marine section, characterized by fluvial and lacustrine deposits. Includes clean sandstones (up to ~2 darcies), conglomerates, and siltstones/claystones. Lower units (to ~12,000 feet) show increased volcanics and coal content.

- **Pure Kahiltna Unit 1**: Displays different stratigraphy with only ~500 feet of equivalent Kenai Group and ~6,700 feet of fluvial clean sandstones, coal beds, conglomerates, and volcanics, time-equivalent to the Hemlock/West Foreland formations.

USGS studies incorporated 41 two-dimensional (2D) seismic lines, gravity and magnetic surveys, and two exploration wells. Conductivity and sonic logs indicate coal seams, and multiple gas shows have been observed in coal formations.

Figure 5-1 Map of Susitna Valley ADNR Leases



Notes: The area is divided into Deep Basin (blue shade), Shallow Basin (orange shade), and Very Shallow (no shade). The yellow path is the proposed road for the area based on the Grant Lake Corporation permit. Red lines are faults based on 2D seismic surveys.

Key: U/D =upthrown and downthrown sides of the faults

In 2025, ASRC CONSULTING AND ENVIRONMENTAL SERVICES requested a petrophysical analysis of the logs from Trail Ridge Unit 1 to be conducted by NuTech Energy Alliance (NuTech). The aim was to evaluate and quantify the presence of gas in this well, as the original operator did not test any of the gas zones in 1980 when this exploration well was drilled aiming to find oil-bearing formations in the Susitna Valley. Figure 5-2 shows a petrophysical analysis of shallow-free gas from this area.

After analysis, several gas pays were identified where good quality gas saturation exists for potential commercial findings. The first zone of interest is at a shallow depth of 1,412 ft true vertical depth (TVD), in the Sterling/Beluga equivalent formation. The permeability is in the order of 40 to 50 millidarcies (md) with good porosity. The estimate is that this type of zone can contain up to 4.5 bcf of gas in a section (640 acres). Figure 5-2 shows a petrophysical analysis of shallow-free gas from this area.

Deeper below that, there is another potential gas-bearing zone, with lower permeability around 10 md and 18 percent porosity (Figure 5-3). This zone has some mobile water based on log analysis; however, it is still a good candidate for development. In a section, this could add approximately 2.5 bcf of gas in place.

In total, there could be approximately 7 bcf of gas per section in the deep basin of the Susitna Valley that can be a very attractive find to be proven during the appraisal process.

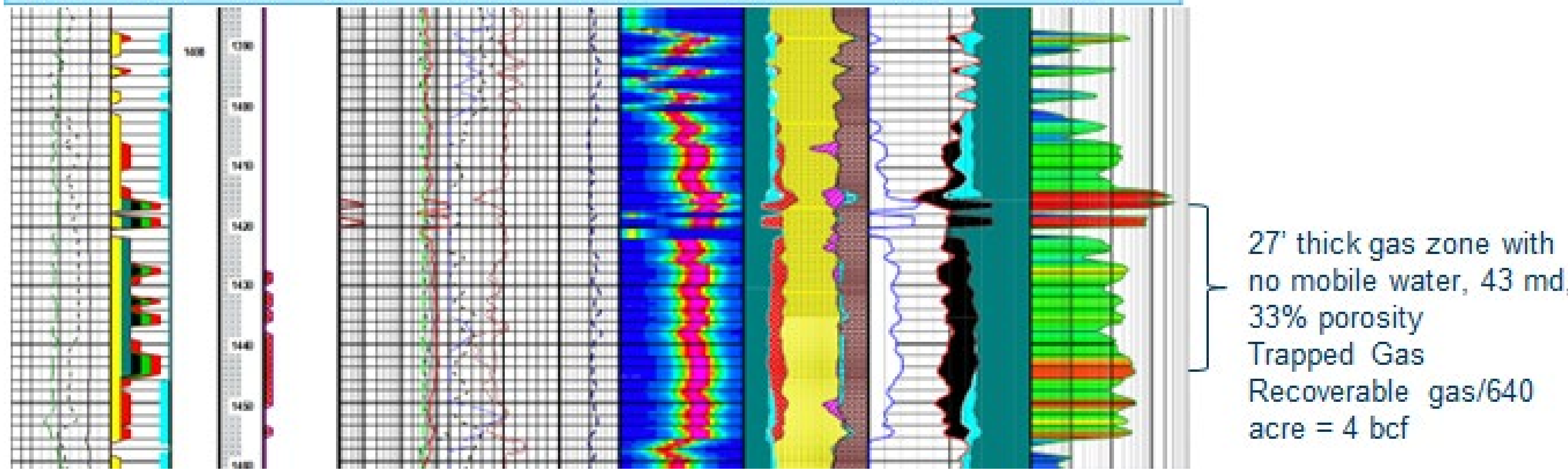
The coal beds also provide another opportunity in the Deep and the Shallow basins of the Susitna Valley. Historically, this area has had many shallow wells that have shown the presence of gas in shallow coal beds, as seen in Rosetta wells and regional studies performed by Pioneer Natural Resources, Inc. (Appendix F). The Trail Ridge Unit 1 petrophysical analysis identified many coal beds within the Tyonek equivalent formation deeper near 11,000 ft TVD that can be prolific.

Figure 5-4 is a petrophysical analysis of the deeper section of the well showing the presence of these coal beds. In particular, the section below 11,000 ft TVD shows a series of thick coal beds that could be a good target for coal bed methane (CBM) development in the lease area. Pure Kahiltna Unit 1 also has the same equivalent coal beds but at shallower depth. The uncertainty with the CBM is the amount of methane that is absorbed by coal, and the porosity and permeability of the cleats and fractures, which is the objective of the appraisal program and testing.

Appendix I has the processed petrophysical interpretation from NuTech that was the input for this analysis.

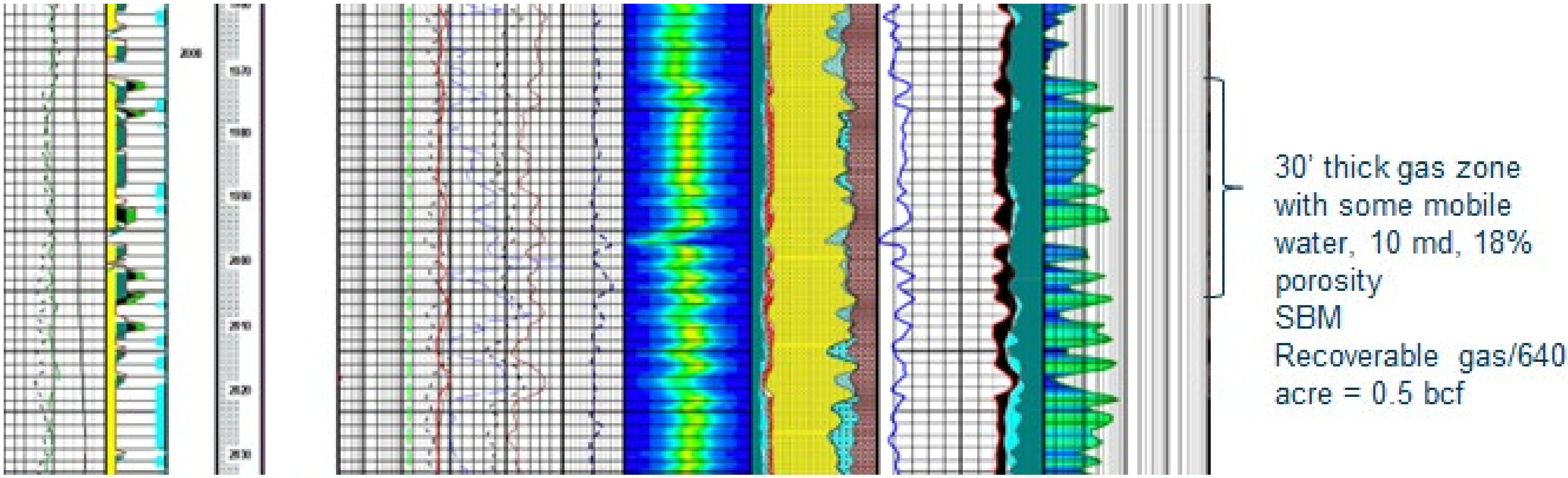
Figure 5-2 Petrophysical Analysis of Shallow Free Gas from Trail Ridge Unit 1

Base TVD (ft)	Top TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
1439	1412	27.2	0.66	0.33	43.4	5.9	1.4	**4.5**



Key: ac = acre
bcf = billion standard cubic feet
PERM = permeability
SBM = sand-bed methane
TVT = true vertical thickness
Avg SW = average water saturation (fraction)
md = millidarcy
PHIE = effective porosity (fraction)
TVD = true vertical depth
U/D = upthrown and downthrown sides of a fault

Figure 5-3 Petrophysical Analysis of Deeper Free Gas in Trail Ridge Unit 1

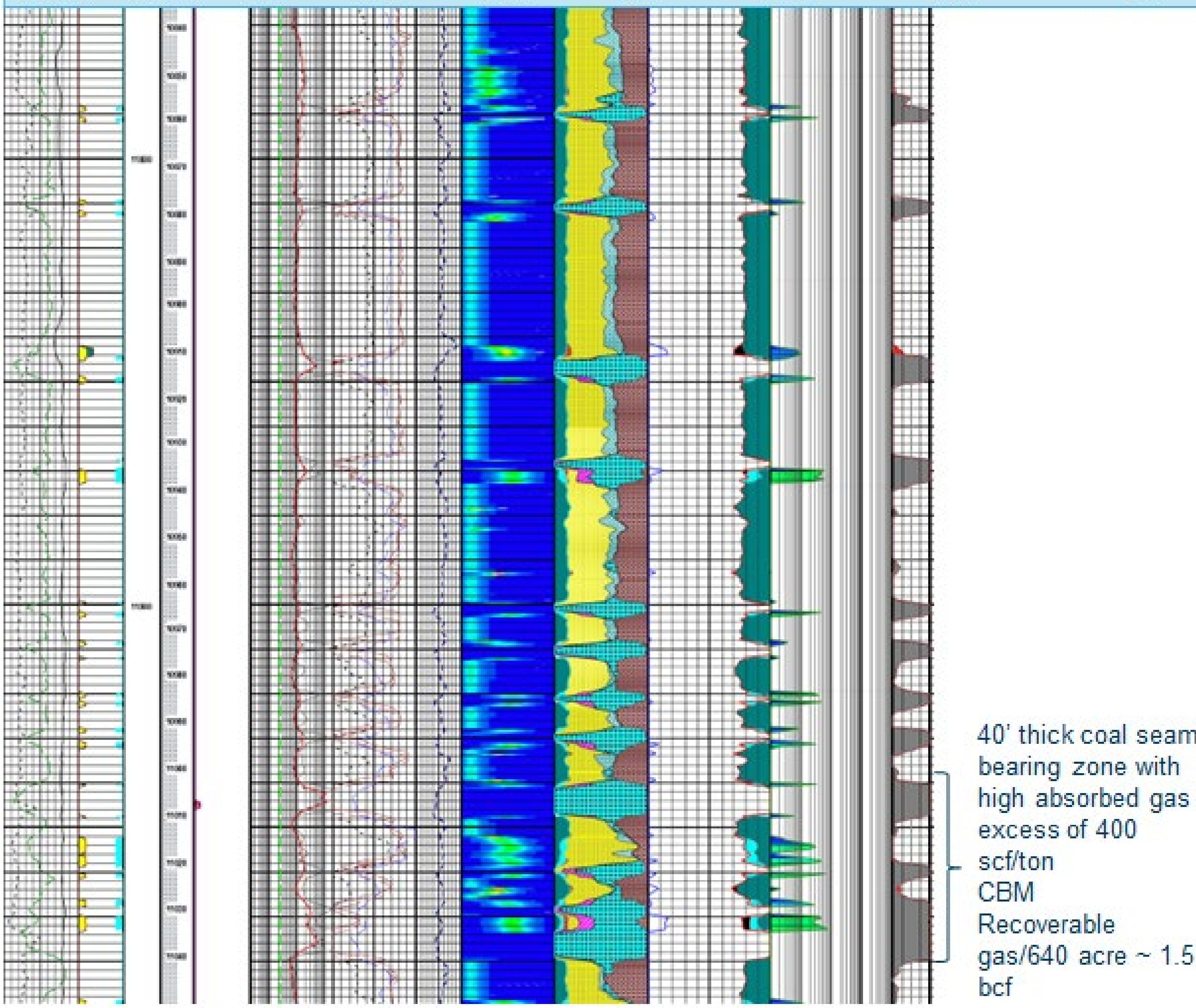


Base TVD (ft)	Top TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
2003	1972	30.4	0.68	0.18	1.6	3.8	1.3	**2.5**

Key:
ac = acre
bcf = billion standard cubic feet
PERM = permeability
SBM = sand-bed methane
TVT = true vertical thickness
Avg SW = average water saturation (fraction)
md = millidarcy
PHIE = effective porosity (fraction)
TVD = true vertical depth

Figure 5-4 Coal Bed Zones in Deeper Section of Trail Ridge Unit 1

Base of TVD (ft)	Top of TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
11040	11000	40	0.98	0.09	0.6	**73.5**	**71.6**	**1.9**



Key:
- ac = acre
- bcf = billion standard cubic feet
- md = millidarcy
- PHIE = effective porosity (fraction)
- TVD = true vertical depth
- Avg SW = average water saturation (fraction)
- CBM = coal bed methane
- PERM = permeability
- scf/ton = standard cubic feet of gas per ton of coal

5.3.1 ASRC CONSULTING AND ENVIRONMENTAL SERVICES Estimated Initial Gas in Place

ASRC CONSULTING AND ENVIRONMENTAL SERVICES has divided the lease area based on gravity and magnetic sediment thickness into three areas: Deep Basin (more than 10,000-ft thick section), Shallow Basin (between 4000 to 7000' thick section) and very shallow (less than 4,000-ft thick section). The gas in place is calculated based on dissolved methane for an average reservoir pressure and temperature of the section (converted into gas–water ratio [GWR]). The deeper basin has a higher GWR than the shallower basins.

The estimate of SBM in the lease area is listed in Table 5-1, while Table 5-2 provides estimates of both CBM and free gas in the lease area.

Table 5-1 Sand Bed Methane (SBM) in the Lease Area

Basin	Area (thousand acres)	SBM TVT (ft)	GWR (scf/bbl)	IGIP (bcf)
Shallow (Yellow)	102	3,000	15	18,564
Deep (Blue)	139	5,000	21	26,042
Very shallow	323	1,500	12	10,374

Key: GWR = gas–water ratio
SBM = sand bed methane
IGIP = initial gas in place, in billion cubic feet
TVT = total vertical thickness

Table 5-2 Coal Bed Methane (CBM) and Free Gas in the Lease Area

Basin	Area (thousand acres)	SBM TVT (ft)	Yield (scf/ton)	GIP (bcf)
Shallow (Yellow)	102	10	250	471
Deep (Blue)	139	20	350	1,890
Very shallow	323	0	150	0
Deep Basin (Free Gas) *	139		7 bcf/640 acres	1,500

Note: * Analysis based on Trail Ridge Unit 1 gas shows in deep basin section associated with dry gas and semi-wet zones.

Key: CBM = coal bed methane
TVT = total vertical thickness
GIP = gas in place, in billion cubic feet

6.0 DEVELOPMENT RISKS AND UNCERTAINTIES

Risks associated with this appraisal and full field development are divided into two primary categories: (1) risks related to dissolved gas in aquifer sands (SBM), and (2) risks related to coal bed methane and conventional trapped gas.

6.1 SBM Risks and Uncertainties

The primary risks and uncertainties associated with the SBM development concept are summarized below and relate primarily to reservoir characteristics, fluid behavior, and operational considerations:

- High permeability and unconsolidated shallow sands may result in excessive sand production
- The assumed GWR of 20 may be too high; petrophysical logs indicate values more in the range of 5-8 GWR range throughout shallow SBM section.
- Localized aquifer contamination may occur if sand is produced above approximately 2,000 ft TVD.
- Extremely high volumes of mobile water shown on petrophysical logs may render the SBM development program inefficient.

Overall mitigation of SBM program risks involves focusing well placement away from shallow SBM targets and toward deeper basin locations that are more favorable for CBM or migrated, conventional trapped gas.

6.2 CBM and Conventional Trapped Gas Risks and Uncertainties

The primary risks and uncertainties associated with CBM and conventional trapped gas development relate to reservoir presence and continuity, trapping mechanisms, seismic definition, and well placement:

- Reservoir Risk and Source – Low
    - High-quality reservoir sands are apparent to 12,000 ft TVD on petrophysical logs.
    - Continuity of coal is uncertain due to sparse well data; however, coal appears to be present regionally on seismic data.
- Trap and Seal – Medium to High
    - No structural map is currently available; one will need to be constructed using existing data from two wells and the available 2D seismic grid to refine well placement and improve the likelihood of encountering structurally trapped gas.

  - The sealing capacity of faults and structural features has a high degree of uncertainty.
  - Structural closure is difficult to assess due to the sparse seismic grid.
- Well Placement – Medium
  - High uncertainty exists in fault dip angles at depth due to limitations in seismic data quality.
  - Only two deep wells are present within the basin, which increases uncertainty in depth conversion and, therefore, in the prognosis of target horizons.

6.3 Other Risks

Other risks that could result in longer-than-expected execution timelines or increased project costs during both the appraisal phase and future development are outlined below:

- **Drilling Costs**: The capital expenditures (Capex) associated with drilling a large number of wells in the Susitna Valley represent a considerable risk to the project and its profitability. ASRC CONSULTING AND ENVIRONMENTAL SERVICES is committed to investigating alternative options for rig deployment and contracting strategies to reduce the cost of well construction for this project. All options are open and will require market research (including potential sourcing of a rig from the Lower 48 or purchasing a rig for the project).
- **Permitting and Environmental Compliance**: Securing permits and ensuring compliance with federal, state, and local agencies is a critical part of the appraisal plan, particularly with respect to the disposal of produced water during the well-testing phase of appraisal.
- **Infrastructure and Access to Land**: Several private properties, mining claims, and exclusion zones within the Susitna Valley and near the appraisal area must be managed to secure proper land access for construction of drill pads, water pits, and access roads for rig and field operation during the appraisal phase.

  Water Handling and Lifting/Disposal: The SBM completions are expected to produce 15,000 to 20,000 barrels (bbls) of water per day. At this rate, the volume of water to be processed and disposed of (in water pits during the appraisal phase, and in injection wells during full-field development) will require processing and disposal facilities and regulatory permitting, which may add significant cost to the project depending on the selected disposal option.
- **Flow Assurance and Well Completion**: High permeable SBM sands may produce solids that can plug wells and interrupt gas production during the test period; appropriate well intervention contingencies and completion designs will be incorporated to mitigate this risk.

- **Drilling Complications and High Nonproductive Time**: Drilling across faults at high angles and through coal beds may increase nonproductive time, add cost to well design, and require additional casing runs to reduce the risk of stuck pipe.

7.0 APPRAISAL PLAN – ASRC CONSULTING AND ENVIRONMENTAL SERVICES PROPOSAL

The objective of the proposed appraisal plan by ASRC Consulting and Environmental Services is to de-risk the future development plans for the Susitna Valley and assess the feasibility of producing gas from sand bed methane (SBM), coal bed menthane (CBM), as well as evaluate the likelihood of free gas zones associated with structural trap in the area. ASRC CONSULTING AND ENVIRONMENTAL SERVICES proposes a three-well appraisal drilling program starting in the winter of 2026, followed by a long-term test period during the summer-fall period in 2027. The outcome of the appraisal drilling and testing program are outlined below:

- Obtain core and log data for coal beds to evaluate coal maturity
- Conduct long-term production testing in CBM
- Conduct production testing in SBM to evaluate the gas and water rates and fluid chemistry
- Evaluate potential structurally trapped gas in the fault region of the deep basin.

Successful completion of the appraisal drilling, testing, and post-test studies will define the scope and direction of future appraisal and development activities in the Susitna Valley. It may be necessary to conduct further appraisal drilling as a result of the initial three-well program to test the broader extent of the resource base in the lease area; however, any additional appraisal activity is subject to further evaluation and funding.

7.1 Proposed Appraisal Plan Scope

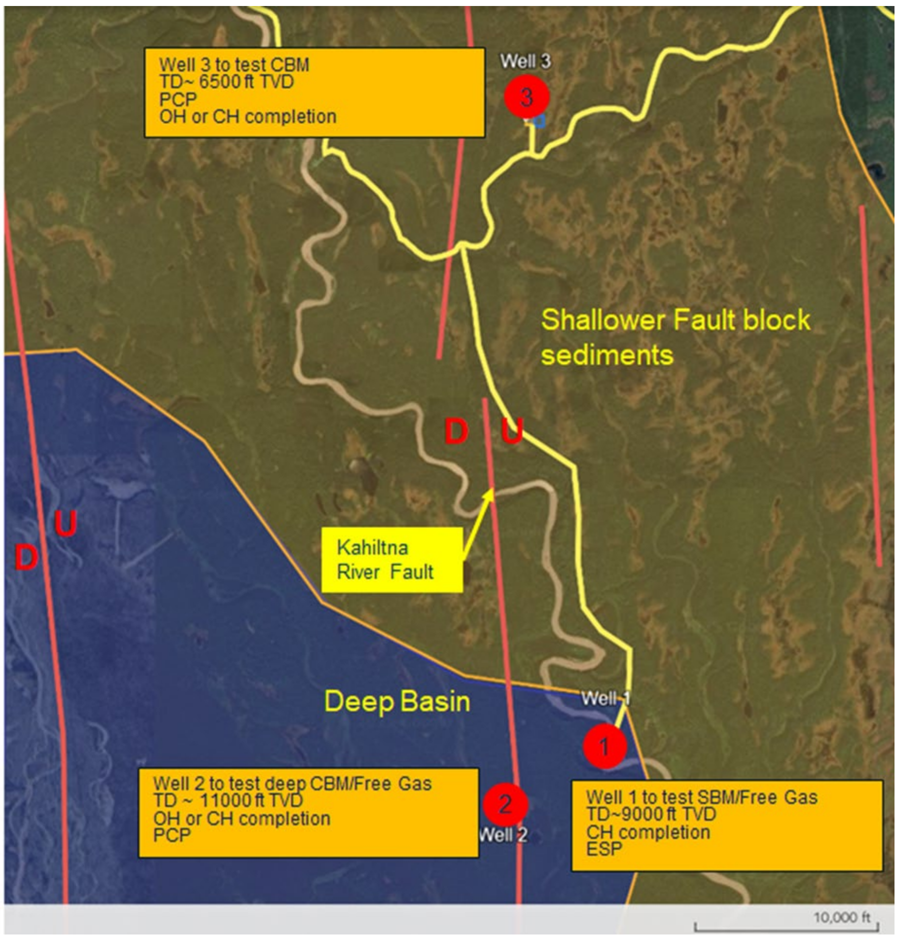
The key elements of the initial appraisal plan for the Susitna Valley are summarized below**:**

- **Planning, Permitting, and Procurement**: Finalize well locations; test two wells for SBM, CBM, and conventional trapped gas; a third well will explore a graben block for deep gas; secure permits (Alaska Department of Environmental Conservation [DEC], Alaska Oil and Gas Conservation Commission [AOGCC], and ADNR); and procure a rig, mobile production unit, and water filtration system.
- **Construction**: Construct roads, pads, and pits in the Grant Lake Corporation area during summer 2026, including two pads with water disposal pits and an approximately 6-mile access road south of the existing Oil Road.
- **Well Construction**: Conduct drilling and completion during winter 2026–2027, with two wells on the south pad, and one well on the north pad.
    - Drill the first well (Well No. 1) in the south pad; core and log the well; and place it on a long-term production test.

- Move the rig to the north pad (Well No. 3), and drill a vertical well to assess CBM and SBM, with appropriate coring and logging.
- Move to the final well in the south pad (Well No. 2) and drill across the fault to evaluate deep CBM and free gas zones.

- **Testing**: Conduct long-term testing in two wells using a production test unit (spring–fall 2027).
- **Post-Testing**: Complete appraisal analysis and next-phase assessment in 2028; perform laboratory analysis of CBM methane; and evaluate future rig deployment strategy.

Figure 7-1 Map of the Susitna Valley Deep and Shallow basins



Notes: The area is divided into the Deep Basin (blue shading), Shallow Basin (orange shading), and Very Shallow unit (no shading). The yellow line is the proposed road alignment for the area based on the Grant Lake Corporation permit and a future road to the south for Wells 1 and 2. Red circles indicate the bottom-hole locations (BHLs) of appraisal Wells 1, 2, and 3. Red lines are interpreted faults based on 2D seismic data.

Key:

CBM = coal bed methane	CH = cased-hole completion	ESP = electric submersible pump
OH = open-hole completion	PCP = progressing cavity pump	SBM = sand bed methane
TD = total depth	TVD = true vertical depth	U/D = upthrown and downthrown

7.2 Permits/Land and Procurement

The initial phase of the appraisal plan is to secure applicable permits, complete environmental studies, and ensure compliance with the U.S. Fish and Wildlife Service, the U.S. Army Corps of Engineers, the Bureau of Land Management, and other federal agencies, as well as obtain the necessary permits to begin construction of roads and infrastructure during the summer of 2026. Another aspect of the permitting process has to do with compliance with the DEC, the AOGCC, and the ADNR, as well as other state agencies for water disposal in pits, construction of two drilling pads, and road extensions. Preliminary discussions with Alaska regulatory agencies indicate that surface disposal of produced water in lined pits, without discharge to rivers or lakes, is the preferred option for the appraisal wells in this phase (Appendix E).

The local Matanuska–Susitna Borrough authorities and communities are also impacted by this development. However, no significant issues are anticipated with the appraisal plan, as it is limited in scope and surface footprint and is expected to be acceptable to local authorities. Early engagement and stakeholder buy-in are crucial to ensure a smooth permitting process and timely execution of the infrastructure plan (road, pits, and pads) and mobilization of the drilling rig.

Regarding the road, pads and pits permitting and land, ASRC CONSULTING AND ENVIRONMENTAL SERVICES will work with Grant Lake Corporation to ensure they have all the resources to secure these permits. Grant Lake Corporation is responsible to secure the permits and be compliant with federal, state and local authorities to construct the appraisal plan roads, pads and pits.

ASRC CONSULTING AND ENVIRONMENTAL SERVICES will facilitate the permitting process for drilling and testing phase of the appraisal plan and coordinate with the drilling team, as well as the testing and operations teams, to ensure timely execution of the program. The key enabler is to initiate environmental studies and federal, state, and local permitting applications as soon as possible in early 2026.

Procurement of materials for the wells is also a process that could take time and should be started as soon as possible. The most crucial items are coring equipment, which may be mobilized from the continental United States, and wellhead equipment with long-lead times. ASRC CONSULTING AND ENVIRONMENTAL SERVICES will design these wells using standard completions with minimal custom-designed equipment and materials. However, starting and progressing the well design early in 2026 will help meet the schedule for the drilling campaign in late 2026.

7.3 Construction Phase

7.3.1 Grant Lake Corporation Road Proposal

Grant Lake Corporation (Grant Lake) holds mining claims and permits roads to gold mine claims in the appraisal area. In preliminary conversations between ASRC CONSULTING AND

ENVIRONMENTAL SERVICES and Grant Lake, Grant Lake has indicated its willingness to extend the existing Oil Road for rig mobilization and to extend the road south to its future claims near the proposed Pad 1 site. ASRC CONSULTING AND ENVIRONMENTAL SERVICES proposes contracting pads, pits, and road construction to Grant Lake due to local familiarity with the area. Table 7-1 summarizes the conceptual plans for Pad 1 and Pad 2.

Table 7-1 Road and Pad Description

Pad	Wells	Pad Size	Water Pit Size	Notes
Pad 1	Well No. 1 & Well No. 2	3 acres	3 acres (10 ft deep)	New road access
Pad 2	Well No. 3	5 acres	3 acres (10 ft deep)	Houses drilling camp during construction

In this phase of appraisal, anticipated to begin in summer 2026, Grant Lake is expected to extend the Oil Road westward, passing the current Pure Kahiltna Unit 1 well location. Grant Lake has gold claims in the area near the Susitna River and has obtained state and local permits to build roads to access its mining claims (pursuant to the Pioneer Law). In preliminary discussions, Grant Lake has also indicated that the company is willing to construct an approximately 6-mile road south toward the proposed drilling pad, which will accommodate Well No. 1 and Well No. 2. Grant Lake Corporation initial proposal is in Appendix H.

ASRC CONSULTING AND ENVIRONMENTAL SERVICES has provided the road, pad, and water disposal pit requirements to Grant Lake for further assessment. The plan is to follow up obtaining a budgetary estimate for the work needed to build the access road, drilling pads, and water disposal pits at these two locations, as shown in Appendix C and Figure 7-2 through 7-4 .

Figures 7-3 and 7-4 show the preliminary design and locations of the drilling and testing pads and associated water disposal pits for the two sites for the two appraisal sites. Pad 1 is 6 miles south of the Grant Lake proposed road extension, near a river bend, and will accommodate two wells designed to assess gas plays in shallow and deep basin areas. Images of the mobile test unit and mobile water treatment unit are also shown in the figures.

Figure 7-2 Grant Lake Permit for New Road to Gold Claims (in Yellow)

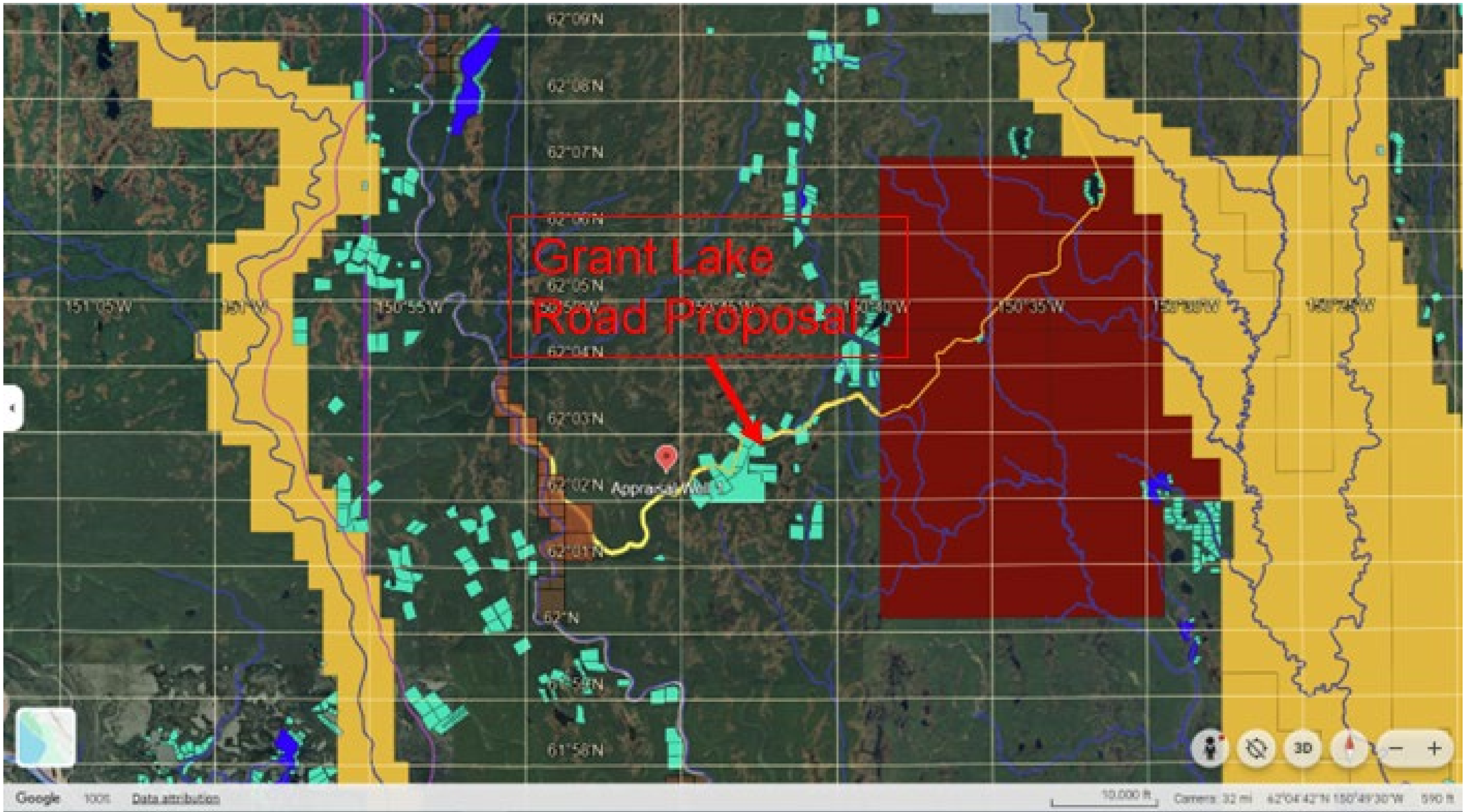


Figure 7-3 Pad 1 Housing Two New Appraisal Wells 1 and 2, 6 Miles South of Oil Road

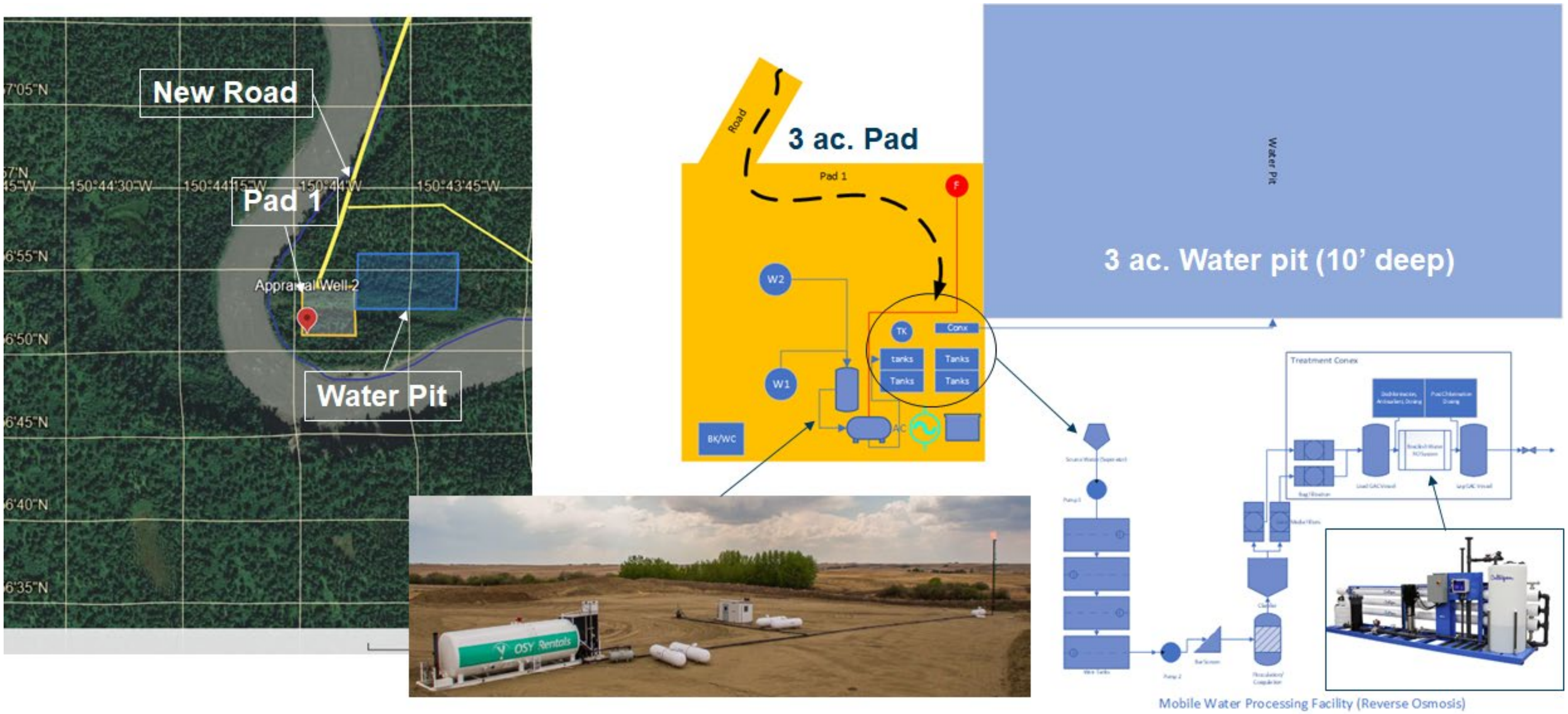
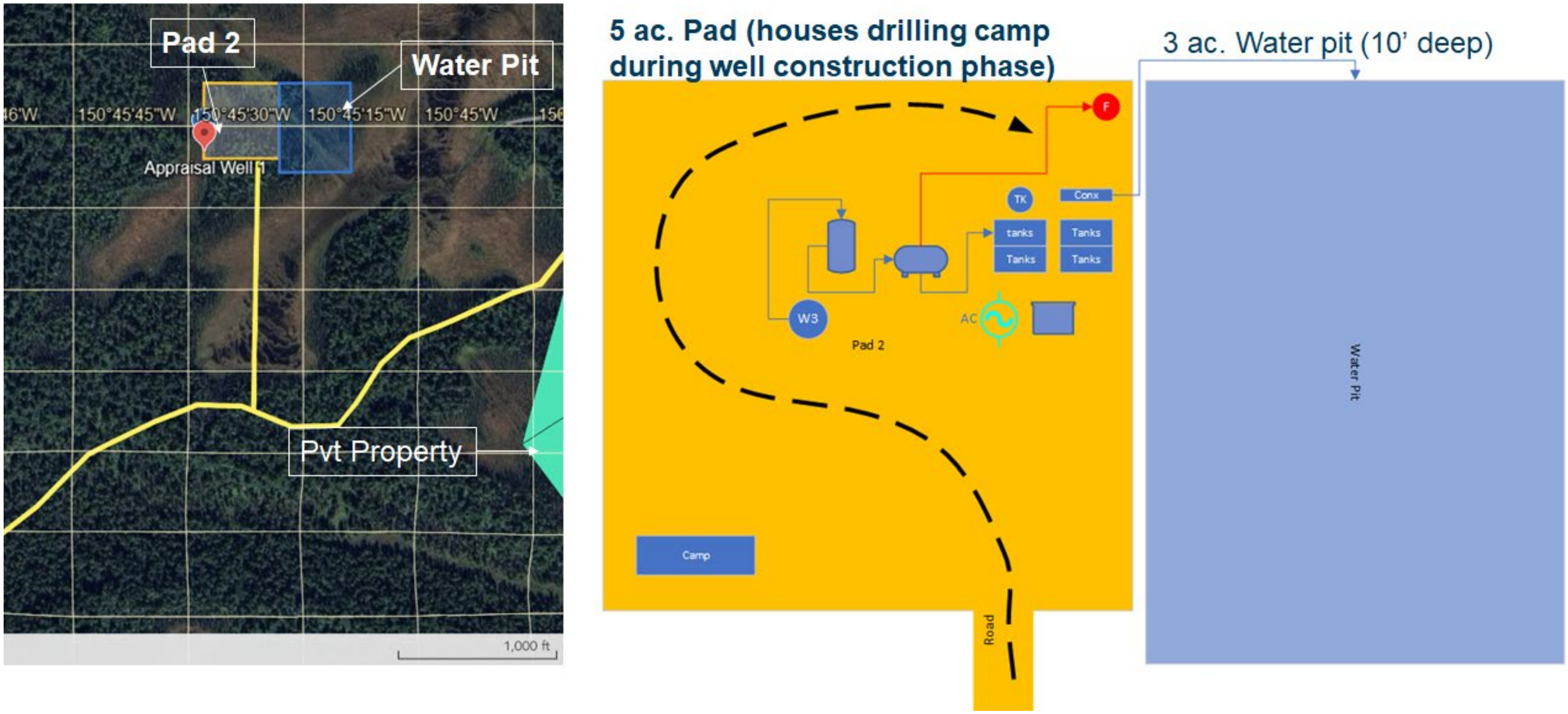


Figure 7-4 Pad 2 Near the Exploration Well Pure Kahiltna Unit 1



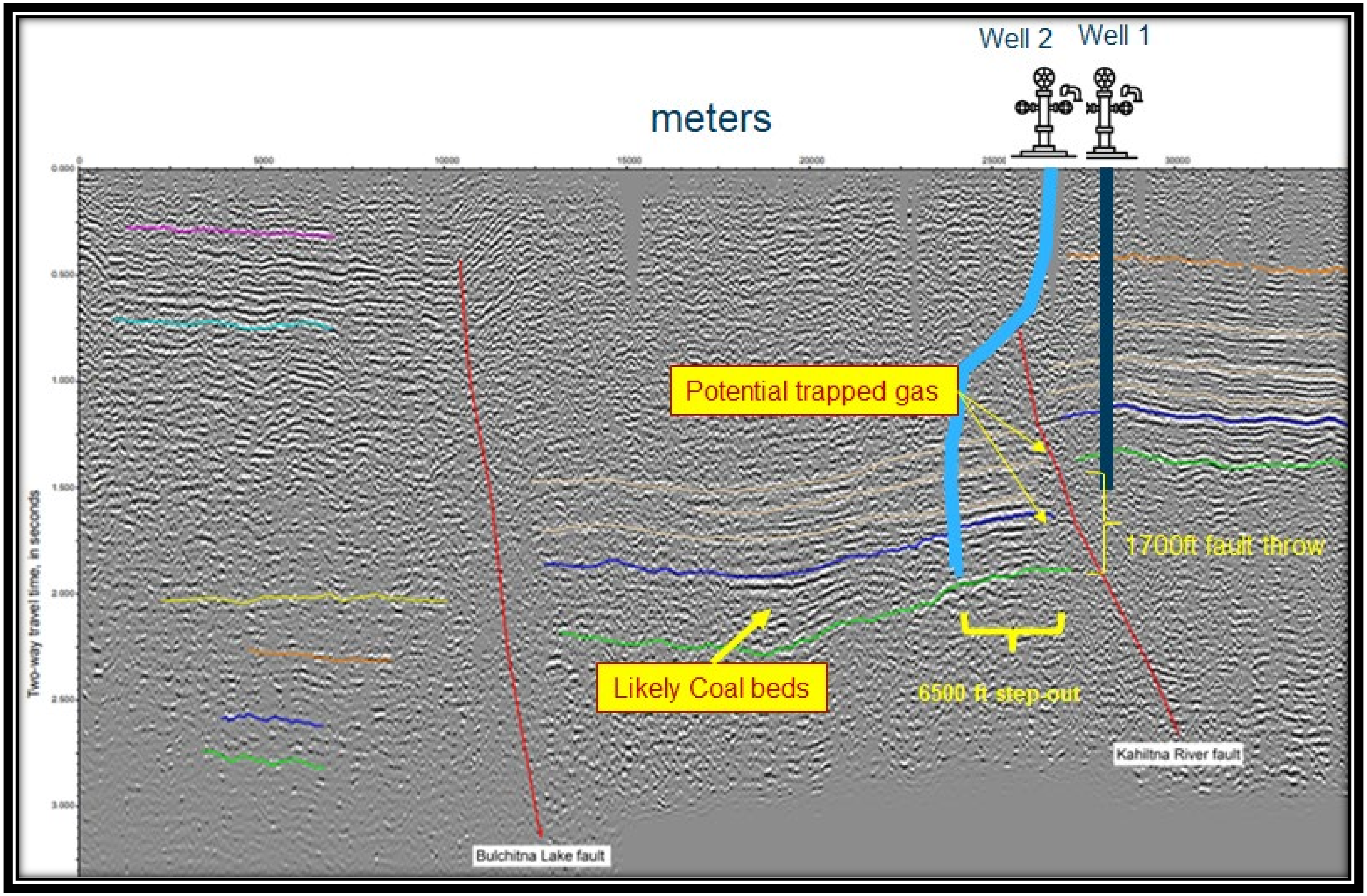
7.3.2 Well Construction

The proposed well construction phase consists of planning, permitting, well design, procurement, rig mobilization, drilling and completion of the three proposed wells, followed by final demobilization of the rig to Kenai. The key elements of the proposed well construction program are summarized below:

- **Rig Contract**: The preferred rig contractor is Nordic-Calista LLC, which has available rigs with the appropriate technical specifications to drill and complete these wells and is favorably located for mobilization. Alternative rigs, such as Hilcorp-owned rigs, could be an option; however, the total cost is not expected to differ materially from the current estimates.
- **Drilling Scope and Cost**: The appraisal program will include extensive formation evaluation and coring to assess the potential resources in the development area. This includes electric-line (e-line) triple-combo logs (full suite), natural remanent magnetization (NRM) measurements, and logging-while-drilling (LWD) data. In addition, extensive coring will be conducted in the wells to assess CBM resources. The drilling program includes drilling a high-angle well across a fault to a deeper area of the basin, which introduces additional cost and risk. These wells are more expensive (approximately $30 million per well) due to the extensive formation evaluation and exploratory nature of the wells. in addition, rig mobilization, crew housing, and catering costs are higher due to rig movement from the Kenai Peninsula, 200 miles away from this site.
- **Logistics and Camp Operations**: During the drilling and completion of the wells, the main drilling camp is stationed on Pad 2 (5-acre pad), and the drilling crew will be housed there, with food and catering brought in from nearby hotels and catering services. The drilling crew will use the south extension road to access Pad 1 during the drilling of Well No. 1 and Well No. 2. For emergency and urgent evacuation, the Oil Road provides access to Talkeetna and Willow urgent care facilities.
- **Workover Contingency**: Also included in the plan is contingency planning for non-rig workovers and rig-based workovers in the event that there is a problem with completion equipment (e.g., pumps, tubing) and intervention is needed while the rig is in the area, thereby eliminating the need to mobilize and demobilize an additional rig later in the season.

The detailed cost analysis by ASRC CONSULTING AND ENVIRONMENTAL SERVICES is provided in Appendix G. Figure 7-5 shows the schematic trajectories of Well No. 1 and Well No. 2.

Figure 7-5 Well No. 1 and Well No. 2 Drilling Trajectories



Note: Well No. 2 is extended across the fault.

7.4 Production Testing

The production test phase of appraisal is a critical path toward commerciality and full development. The objective of this phase is to produce two of the three wells targeting SBM and CBM, and to conduct a short-duration test of the free gas zones. The test period will be customized based on early assessment of drilling, coring, and formation evaluation results during the well drilling and completion phase. However, it is expected that the CBM test will have to be performed over a longer period (up to 3 months) to dewater the coal beds and cleats and to initiate gas production during the test period. The CBM test period may be extended depending on test performance and available funding. After the production test, ASRC CONSULTING AND ENVIRONMENTAL SERVICES will monitor pressure trends in the well to analyze the extent of the reservoir and potential drainage area. Similar tests, but shorter in duration, will be performed on the SBM (dissolved gas in aquifer sands) and on free gas zones.

The wells will be completed with both electric submersible pumps (ESPs) and with progressing cavity pumps (PCPs) for SBM and CBM respectively. The advantage of ESPs is that they can draw high water-production rates from SBM (up to 20,000 bbls/day) and produce gas at that rate, followed by step-down testing to 5,000 bbls/day to evaluate well productivity and reservoir response through multi-rate testing.

In CBM applications, the PCP pump is the preferred pump in conjunction with an open-hole dynamic cavity completion. The PCP pump can handle solids production in water; however, it has a lower water-rate capacity, which is appropriate for coal bed methane production based on industry experience in the continental United States and around the world.

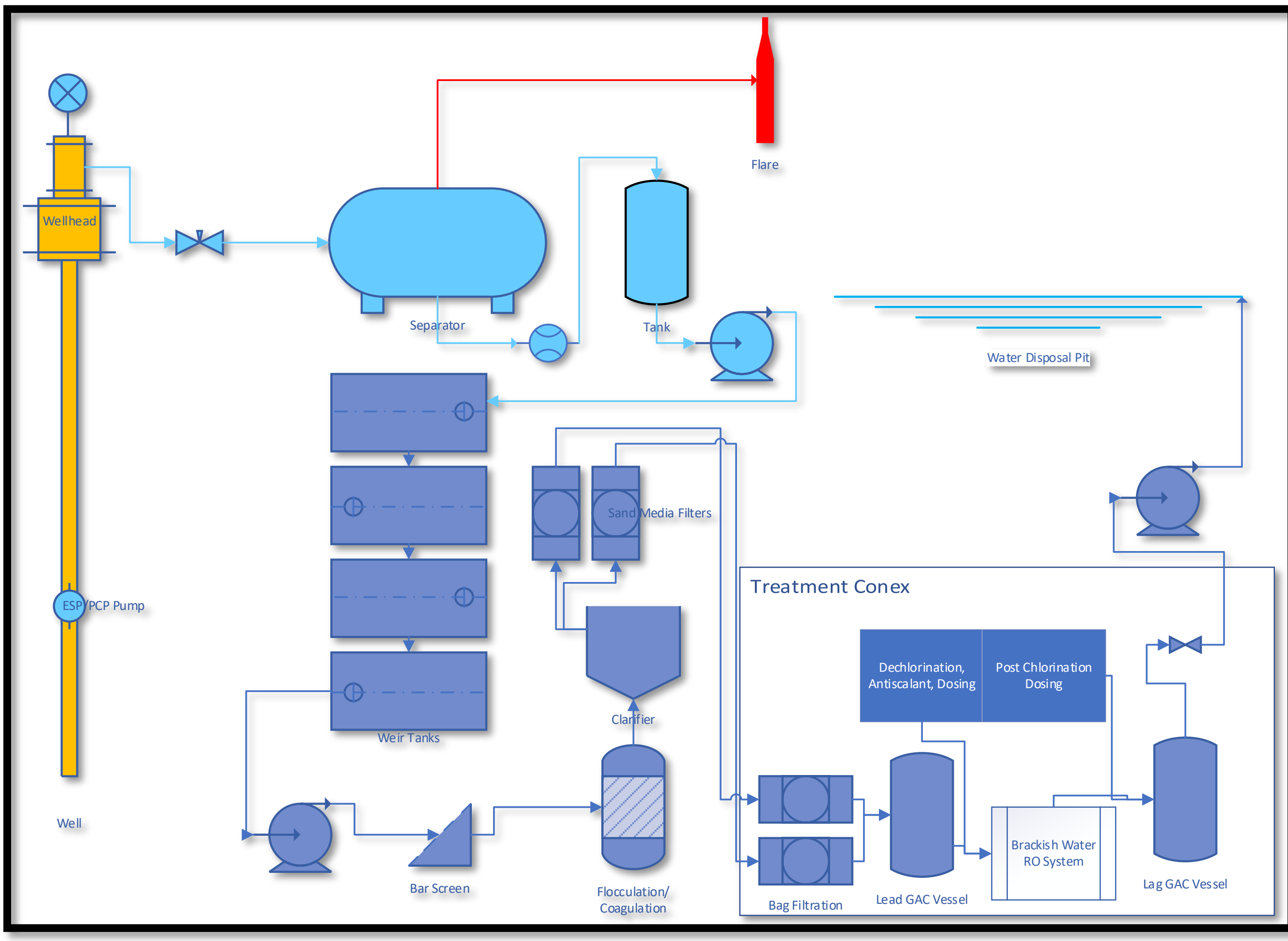
Another key aspect of this phase is operations and production handling during the production test. It is possible that the test period will run for a minimum of 7 months (from April 2027 to November 2027). ASRC CONSULTING AND ENVIRONMENTAL SERVICES will deploy a mobile test unit (rented from OSY Oilfield Services Ltd. in Canada; see Appendix H) and the ASRC CONSULTING AND ENVIRONMENTAL SERVICES Water Filtration Unit (WFU) (Appendix H) which is a reverse-osmosis (RO) design, modularized and equipped with granular activated carbon (GAC) and solids filtration units, to ensure the produced water meets regulatory requirements for disposal into unlined pits. A three-person crew will operate the mobile facilities on a 24/7 rotation during this period. They will be housed in a local hotel, with transportation to and from the pads. In addition, a small camp on-site will be established at Pad 1 and Pad 2 to house break room and wash facilities, as well as a control room for operation of the mobile units.

The disposal of produced fluids (gas and water) is outlined below:

- Gas and water are produced from the well through a 2-inch pipeline to a test separator, where water and gas are separated. The gas is sent to a flare stack located 300 ft away from the separator.

- The water is routed via pumps to storage tanks and to the inlet of the WFU.
- The filtration unit uses a series of tanks, filters, and GAC to remove trASRC Consulting and Environmental Services of hydrocarbons. In addition, an RO unit (Culligan Co.) will be used to reduce total dissolved solids and salinity from 20,000 parts per million (ppm) to less than 1,000 ppm. The capacity of the RO is expandable, and additional RO units can be deployed as water-production rates increase.
- The treated effluent water is then pumped to an open water disposal pit (unlined, 3-acres in size). Figure 7-6 shows a schematic of the mobile units to be deployed for production testing on Pad 1 and Pad 2.

Figure 7-6 Schematic of the Mobile Production Unit and Water Filtration Unit



7.5 Post-Testing Analysis

The post-drilling, completion, and testing phase includes activities associated with evaluation of the data captured from the appraisal wells. These activities include the following:

- Analysis and reporting of core descriptions and special core analysis (SCAL), as required.
- Review of production test results and reservoir modeling based on production test and pressure buildup analysis.
- Water and gas chemical analyses to inform disposal requirements, gas sales quality, and sampling strategies for water disposal options (e.g., pits or disposal wells).
- Geophysical and geological modeling and assessment of the resource area and volumes to support future development planning.
- Laboratory analysis of coal desorption data to assess CBM resources and potential reserves.
- Petrophysical evaluation of well logs and integration of results into geological and geophysical models.
- Mapping of coal beds, horizons, and faults.
- Initiation of market research and requests for information related to drilling rigs available within and outside of Alaska, including rig purchase options for Denali P&G.
- Development of multiple development options for the resource base and progression of the project to the Select/Define stage.

7.6 Appraisal Program Schedule and Cost

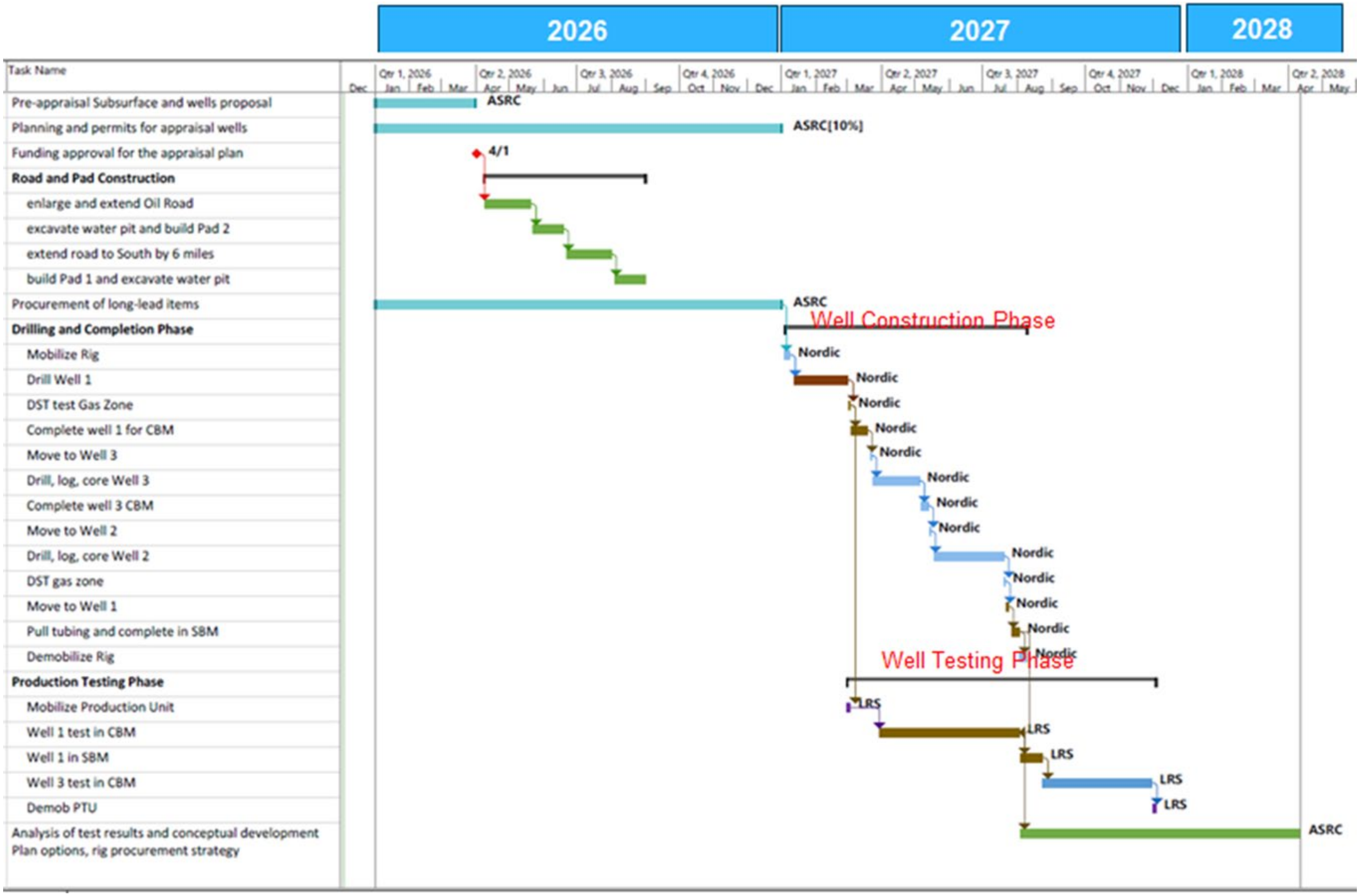
7.6.1 Appraisal Plan Schedule

Figure 7-7 is a preliminary schedule for the appraisal plan, assuming the project begins in January 2026. A summary of the schedule is provided below.

- Pre-appraisal subsurface characterization, including seismic data interpretation and geophysical modeling, structural and fault plane mapping, and finalization of the bottom-hole locations (BHLs) of the proposed appraisal wells (by end of March 2026)
- Permitting, environmental studies, and related regulatory activities, which is anticipated to continue through the end of 2026.
- Road construction, commencing in April 2026 and ending in September 2026 by Grant Lake Corporation (including acquiring the permits from all entities)
- Procurement of long-lead items and critical equipment, which must begin early on in 2026, particularly for wellhead and completion equipment.
- Well construction, beginning in late 2026 with drilling of Well No. 1 and ending with drilling of Well No. 2, after which the rig will demobilize in summer 2027.

- Mobilization of the production testing unit and WFU, commencing in April 2027 in Pad 2. The test period for the two wells will last 7 months, with the units demobilizing in November 2027.
- Post-appraisal analysis and reporting, expected to occur from November 2027 to April 2028.

Figure 7-7 Appraisal Plan Project Schedule



7.6.2 Estimated Cost

The proposed appraisal cost is estimated to be $155.2 million, with $93 million associated with drilling and completion of the wells, as they will require mobilization of the rig from the closest area in Kenai. This cost estimate includes $45 million for road, pads and water pit construction (Appendix H); however, this is subject to validation with the subcontractor, assumed to be Grant Lake. Another aspect of the appraisal is the data gathering from drilling and completion, which includes formation evaluation and assessment of the reservoir/coal beds. An estimated $15 million is considered for geological reports, mud logging, coring, and e-line) logging, including magnetic nuclear resonance (MNR) logs. Table 7-2 provides a breakdown of the appraisal program cost by ASRC CONSULTING AND ENVIRONMENTAL SERVICES.

Table 7-2 Appraisal Plan Cost

Item	Cost (USD)
Road, pad, and pit construction – Grant Lake	$45,000,000
Engineering and permitting (well plans, permits, facility design)	$4,000,000
Rig MOB/DEMOB	$4,500,000
ASRC CONSULTING AND ENVIRONMENTAL SERVICES well supervision and coordination	$3,000,000
Well cost (D&C of three wells)	$80,000,000
Testing of two wells (OSY unit, including. transport)	$200,000
Additional well work (e.g., tubing, pump)	$5,000,000
Water filtration and disposal (RO/filtration system)	$4,000,000
Operators/transportation (7 months, 3 x 24 @ $105/hr)	$2,000,000
Hotels, camps, and services	$2,500,000
Road and pad maintenance	$1,000,000
Project management	$1,000,000
Post-appraisal select/define activities (labs, studies, permits, surface facilities and wells design)	$3,000,000
Total	**$155.2 million**

Key: ASRC CONSULTING AND ENVIRONMENTAL SERVICES = ASRC Consulting & Environmental Services, LLC
DEMOB = demobilization
D&C = drilling and completion
e-line = electric line
hr = hour
LWD = logging while drilling
MOB = mobilization
MWD = measurement while drilling
OSY = OSY Oilfield Services Ltd.
P&A = plug and abandonment
RO = reverse osmosis
USD = U.S. dollar

Notes: P&A cost not included (could be up to $15 million if additional rig mobilization is required). ~$15 million expected for coring/formation evaluation (e-line, MWD/LWD) and geological support during drilling.

8.0 ECONOMICS AND OUTCOMES

8.1 Development Plan (Successful Appraisal Outcome)

The plan is based on a stage-gate approach commonly used in industry for capital investment. The initial stage is the Appraisal stage (ASRC CONSULTING AND ENVIRONMENTAL SERVICES proposal in this document).

8.1.1 Appraisal Stage Overview

The Appraisal plan includes the following key activities:

- Subsurface and geophysical studies to finalize bottom-hole locations (BHLs) and well design.
- Permitting and procurement activities for the rig and materials, including roads, pits, and pads (spring 2026).
- Road construction and infrastructure development (April–September 2026).
- Rig mobilization to the Susitna Valley and drilling of three appraisal wells (winter 2026).
- Mobilization of mobile test units and the water filtration system and production testing of wells (beginning April 2027; up to three months per well).
- Laboratory analysis of well logs and core data to evaluate coal quality and maturity.

8.1.2 Toll Gate Decision Framework

In the toll-gate approach, there is an opportunity to exit the project at any toll gate depending on the technical and commercial outcomes of the project at that stage. If the appraisal is successful in meeting its objective and success criteria, then, at the toll-gate review, a recommendation will be made to advance the project to the next phase, the Select/Design stage, in April 2028.

8.1.3 Select/Define Stage

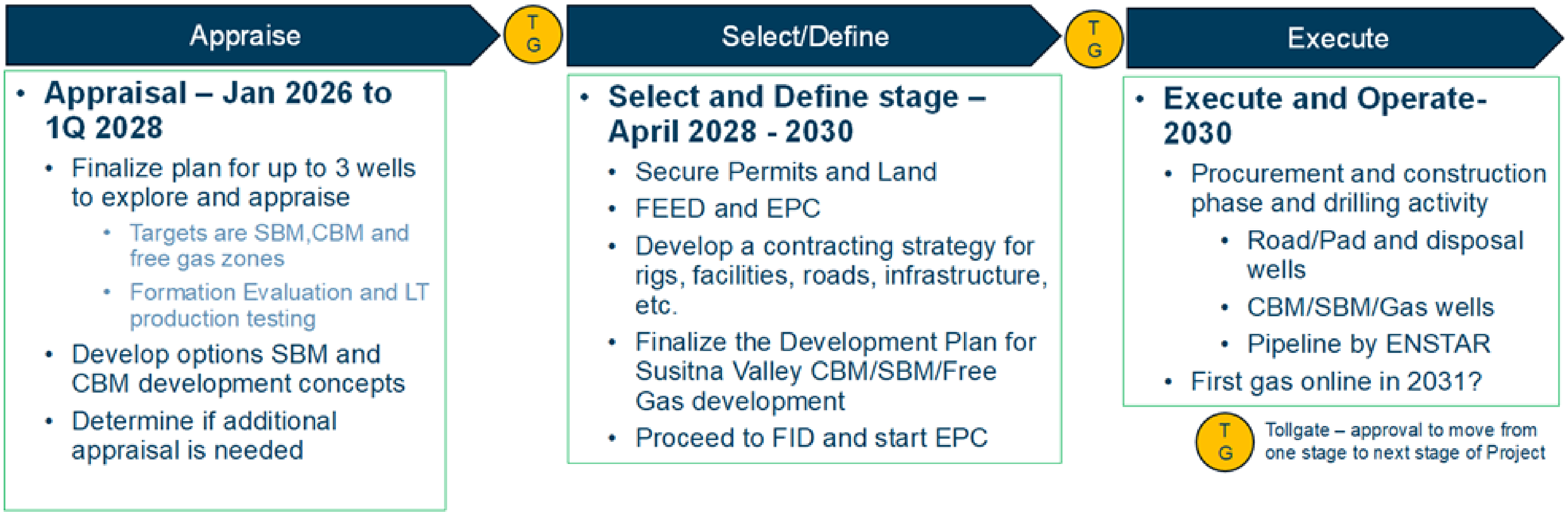
In Select/Define stage, depending on the outcome of the appraisal and the most economically and technically feasible development option, a detailed front end engineering design (FEED) will be completed, and engineering, procurement, and construction (EPC) activities will be initiated following the final investment decision (FID).

The Select/Define stage is expected to conclude in 2030. At the subsequent toll-gate review, based on the outcome of the development evaluation, a recommendation will be made to either advance the project to the Execution phase or terminate the project if it does not meet commercial or technical success criteria.

8.1.4 Execute Stage

The Execute stage begins with construction of infrastructure, pads, and roads, followed by seasonal drilling of development wells, early production testing, pipeline construction, and first gas into the pipeline in 2031. Figure 8-1 summarizes the capital project plan. At this stage, the project is fully sanctioned, and commitments have been made to contractors and suppliers; procurement activities are underway, and all required permits have been obtained to implement the development plan.

Figure 8-1 Project Maturation Using Stage Gate (Tollgate) in Capital Projects



Key:
BHL = bottom-hole location
EPC = engineering, procurement, and construction
FEED = front-end engineering design
SBM = sand bed methane
CBM = coal bed methane
ENSTAR = ENSTAR Natural Gas Company
FID = final investment decision
TG = toll gate

8.2 Scenarios and Economic Evaluation

If the appraisal plan is successful and demonstrates the economic feasibility of gas production from the Susitna Valley, up to three development scenarios may be identified for detailed economic analysis and potential execution. These three scenarios are listed below:

- **Scenario 1: CBM-only development.** This scenario would require a large number of relatively inexpensive development wells (both producers and disposal wells). This approach is analogous to other CBM developments in the continental United States, such as the Powder River Basin in Wyoming.
- **Scenario 2: SBM-only development.** The number of wells in this scenario is lower than for CBM, assuming no material decline in gas rates (and associated water rates) over time due to constant pressure from aquifer recharge. The well count will be an order of magnitude lower than for CBM; however, water disposal costs are higher due to the high volumes of water production per producing well.
- **Scenario 3: Free gas-only development.** This scenario is by far the most economical and lowest capital expenditures (Capex) and operating expenditures (Opex) due to dry gas production. This scenario is economically feasible even at higher per-well drilling and completion costs.

Table 8-1 shows a comparison of the three scenarios. The key assumptions common to all scenarios include supply of approximately 35 bcf/yr for 30 years to ENSTAR, and development drilling costs of $2 million per well (including producer and disposal wells). The assumed costs for workovers include pump replacement costs at $2 million per ell and individual workover costs of $0.5 million per workover, with water—handling costs of $0.05/bbl water handling cost. The assumed gas-handling cost is $0.8 per Mscf.

Table 8-1 Comparison of Development Scenarios and Economic Metrics

Scenario	Wells	Capex ($ thousand)	Opex ($ thousand)	IRR (%)	NPV ($ thousand)
CBM only (no free gas; no commercial SBM)	1,600	8,000	6,700	54	1,022
SBM-only (commercial SBM ≥1,500 ft; no CBM; no free gas)	330	1,232	8,030	27	1,430
Free gas-only (no commercial SBM/CBM)	237	1,452	2,180	88	2,771

Note: Economic results are based on common assumptions described in the text, including gas supply to ENSTAR, drilling and workover costs, water-handling costs, and gas-handling costs.

Key:
Capex = capital expenditures
CBM = coal bed methane
IRR = internal rate of return
NPV = net present value
Opex = operating expenditures
SBM = sand bed methane

Key items forming the basis of cost for the above economic analysis are outlined below:

- Up to 12 wells per pad (including disposal wells)
- 2 percent inflation rate
- Gas price of $12/1,000 British thermal unit (Btu), escalating by 2 percent year-on-year.
- 5-year ESP/PCP pump life (one rig workover every 5 years of production)
- Up to two water disposal wells per pad (CBM/SBM)
- 12.5 percent royalty

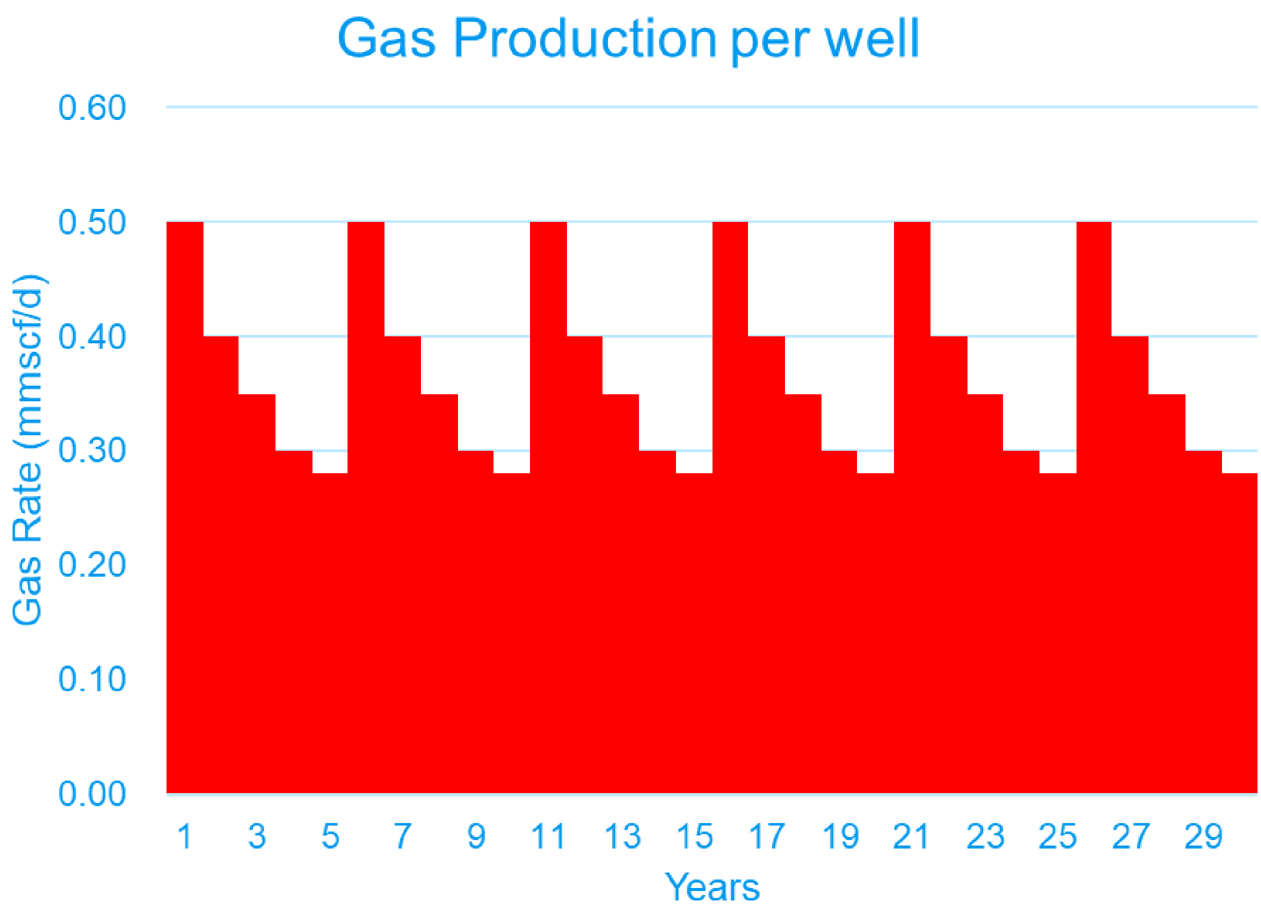
In all scenarios, the key assumption for economic success relies drilling and completion costs being on the order of $1.5 million to $2 million per well. This is lower than costs associated with the current limited drilling rig market in the Kenai Peninsula. Denali P&G, with support from ASRC CONSULTING AND ENVIRONMENTAL SERVICES, will pursue a drilling rig strategy to secure a fleet of rigs for this project that are owned by the operator (Denali P&G) and operated by ASRC CONSULTING AND ENVIRONMENTAL SERVICES or an affiliate. There are two reasons for owning the drilling rigs:

- Rig availability at all times for new drilling and workovers. This rig fleet would be focused on drilling development wells during the first 5 years, followed by a combination of new wells and workovers.
- Lower drilling and workover costs, as crews and rigs would be managed by ASRC CONSULTING AND ENVIRONMENTAL SERVICES, and the cost of rig acquisition would be amortized over the 30-year life of the project.

8.3 SBM Conceptual Long-term Development Concepts

The conceptual development plan for SBM in the Susitna Valley requires adequate appraisal to confirm the extent of the consolidated sandstone formations and the distribution and density of coal beds within the sand. The ideal development concept is to identify five to six thick sand zones with 2- to 10-ft-thick coal beds that act as a gas source for the water-bearing sand zones. The depletion strategy is to produce 15,000 to 20,000 barrels of water per day (bwpd) from each well on a 160-acre well spacing. As the aquifer is depleted, gas is desorbed from the coal beds and produced as free gas from perforations in the water-bearing zone. Dissolved gas within the aquifer, which is a separate process from the gas desorption from the coal beds, is also produced at these rates. With multiple aquifer intervals averaging 200 ft in thickness, it is possible to produce one zone and recomplete the well in shallower zones every 5 years on average. The production profile associated with this technique is shown below.

Figure 8-2 Type Well Production in SBM over 30 Years

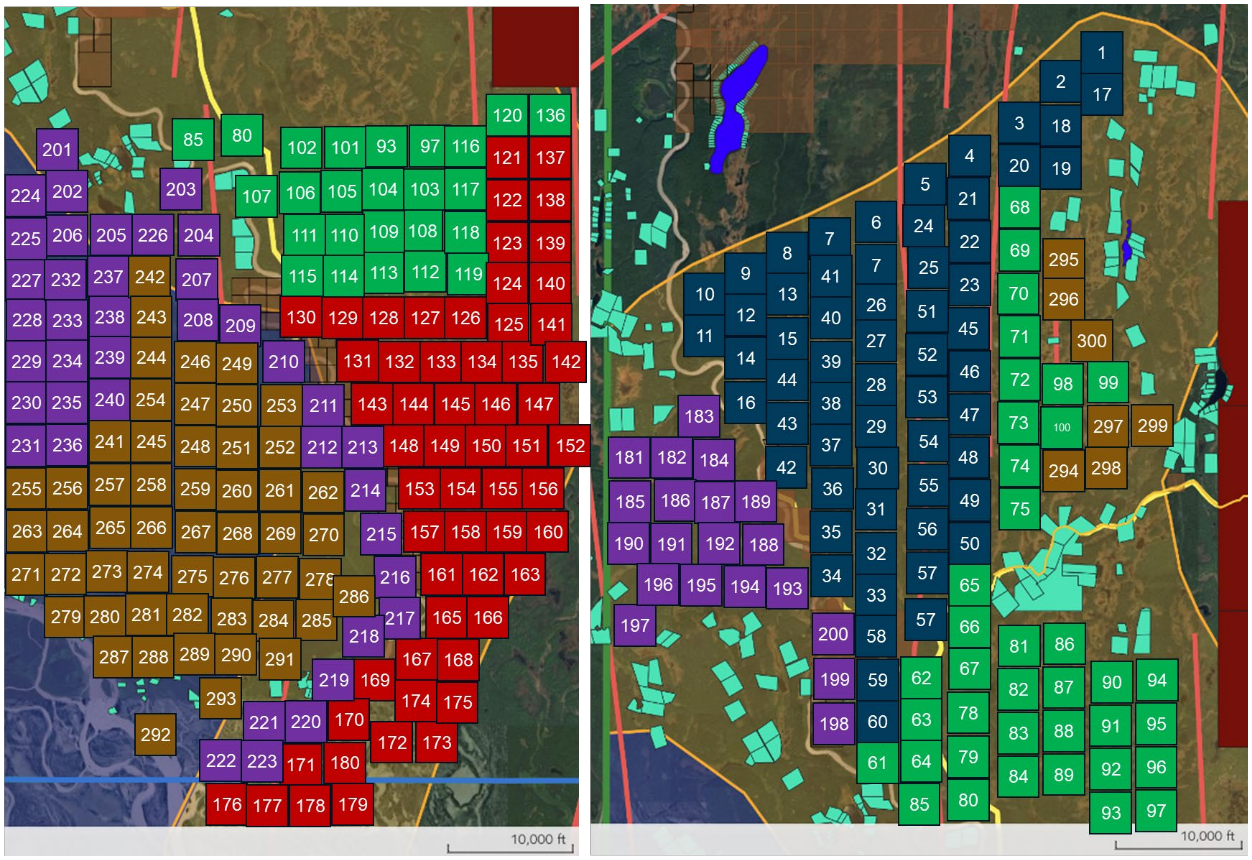


Based on the basin analysis and areas suitable for development where there is a higher likelihood of encountering deeper sediments and a greater density of coal beds, the development is most likely to involve a 5-year, phased (Phase I through Phase V) drilling program starting in 2030 upon successful appraisal and delineation. The drilling phase is anticipated to conclude in 2036, and production is expected to ramp up from 2030 to 2035 to more than 100 Mmscf/d, which is equivalent to 35 bcf/year of gas delivered to ENSTAR (total demand from ENSTAR).

The spacing of the wells is conceptual at this point; however, the area of development is prioritized based on access and infrastructure availability, as the Susitna Valley has a high density of rivers and streams with two large rivers (Khalitna and Susitna) flowing through it. in the first three phases of the development, the focus is on developing the area east of the Kahiltna River. In Phase IV and Phase V, the proposed wells are in the deeper basin and extend westward across the Kahiltna River. ASRC CONSULTING AND ENVIRONMENTAL SERVICES expects this phase to be more expensive and challenging for rig and equipment mobilization, and it may require infrastructure development (roads, pads, and facilities) to be executed on a seasonal basis.

Figure 8-3 demonstrates the location of the future development phases, and each color corresponds to the phasing of the wells. The wells are vertical to near vertical, with 10 producing wells in each drill site (pad) and up to two disposal wells per pad. We envisage a water- and gas-handling facility at each pad, remotely operated, and minimally manned. There will be a central gas facility to condition the gas and compress it to the export line. The export pipeline is assumed to be in place (constructed by ENSTAR) by the year 2030.

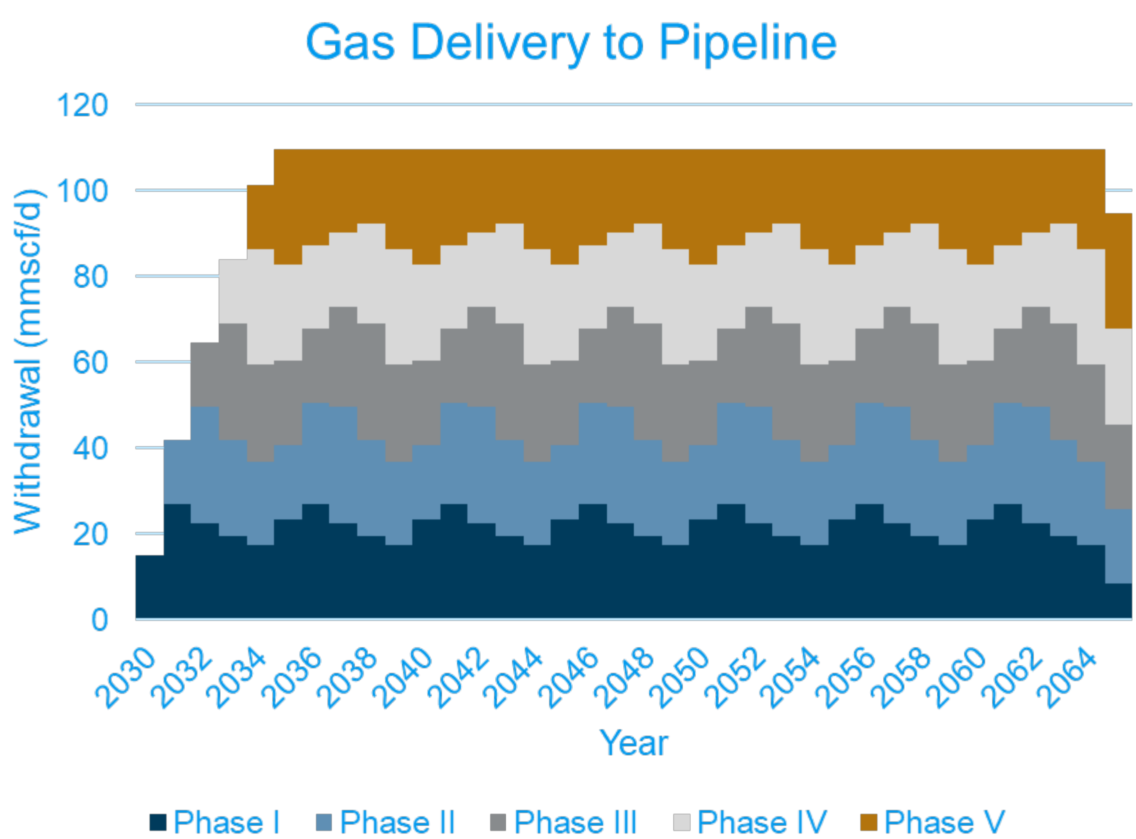
Figure 8-3 SBM Conceptual Wells (Phase I through Phase V)



Notes: Deep blue indicates Phase I wells; green indicates Phase II wells; red indicates Phase III wells; purple indicates Phase IV wells; and brown indicates Phase V wells. Wells are spaced on approximately 160-acre spacing. Development avoids private lands and Mat-Su Borough–reserved lands.

Based on this development, the project is expected to deliver nearly 100 Mmscf/d of gas into the export pipeline to ENSTAR, starting in 2030 (best-case scenario). The produced water is to be re-injected into the aquifer; however it is necessary to maintain sufficient aquifer depletion to ensure that the desorption process in the coal beds is occurring. It is also necessary to periodically re-complete these wells in different sand packages over the years to continue delivering economically viable gas production into the pipeline. Total SBM production is estimated at approximately 1.2 Tcf over a 35-year production period, based on analogues and benchmarks from the continental United States and estimated gas-in-place volumes in the Susitna Valley. Figure 8-4 shows the long-term production profile by development phase.

Figure 8-4 Gas Delivery to ENSTAR from SBM for a 30-Year Period



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Appendix A
USGS Regional Studies
in Cook Inlet and Susitna Valley

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USGS
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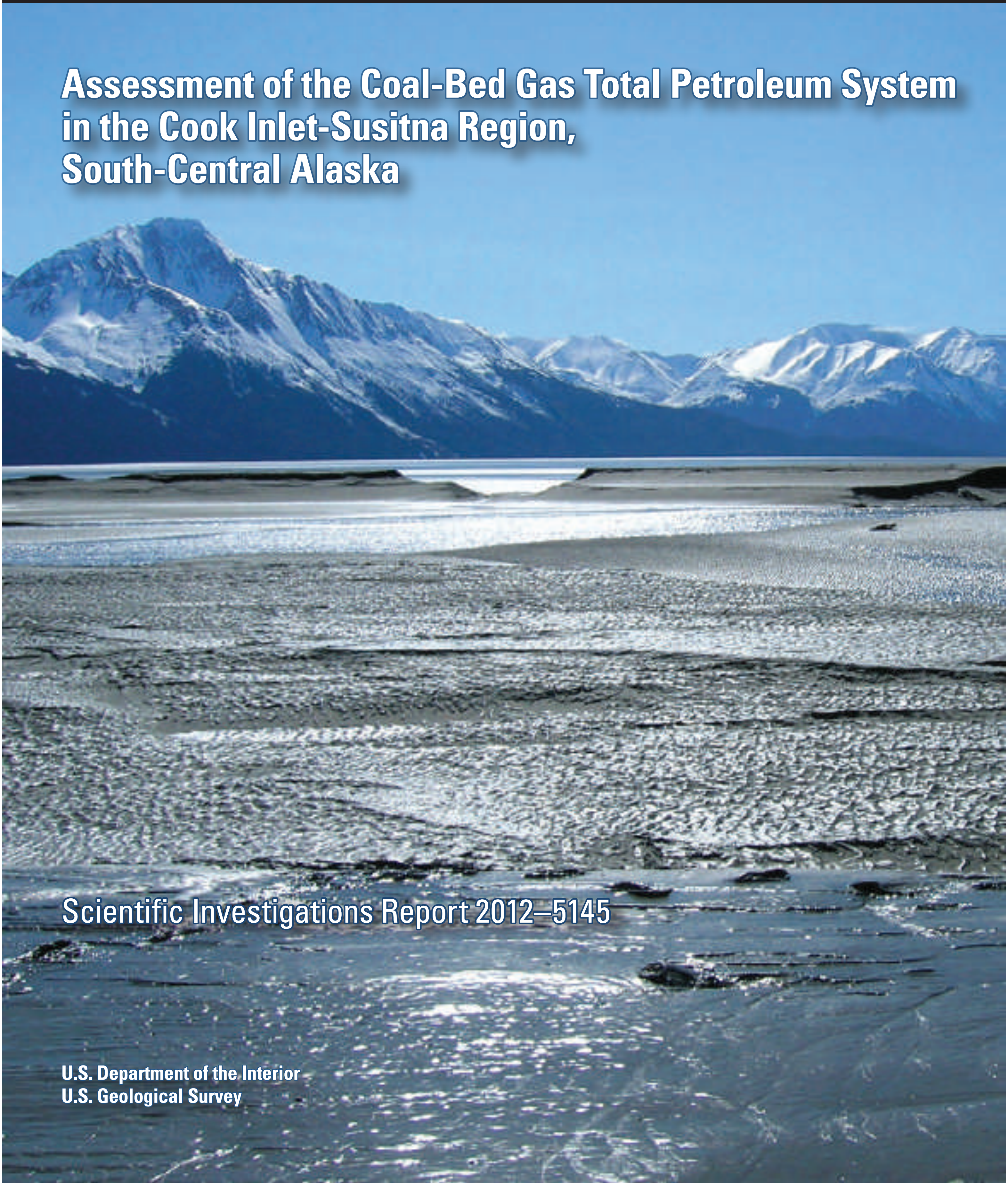
Assessment of the Coal-Bed Gas Total Petroleum System in the Cook Inlet-Susitna Region, South-Central Alaska



Scientific Investigations Report 2012–5145

U.S. Department of the Interior
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Cover photo. View to the southwest across intertidal sand flat along theTurnagain Arm of the Cook Inlet with Kenai-Chugach Mountains in background. Sand flat is located near Girdwood, Alaska, on northern shore of Turnagain Arm, and distance to mountains on southern shore is approximately 7 kilometers (4.3 miles).

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Conversion Factors

Multiply	By	To obtain
	Length	
meter (m)	3.281	foot (ft)
meter (m)	1.094	yard (yd)
kilometer (km)	0.6214	mile (mi)
mile (mi)	1.609	kilometer (km)
	Area	
acre	0.004047	square kilometer (km^2)
	Volume	
cubic centimeter (cm^3 or cc)	0.06102	cubic inch (in^3)
cubic foot (ft^3)	28.32	cubic decimeter (dm^3)
cubic foot (ft^3)	0.02832	cubic meter (m^3)
	Mass/weight	
gram (g)	0.03527	ounce, avoirdupois (oz avdp)
ton	0.9072	megagram (Mg) or metric ton (t)

The isotope ratio of carbon-13 to carbon-12 relative to the Pee Dee Belemnite (PDB), in per mil, is notated as δ13C.

Assessment of the Coal-Bed Gas Total Petroleum System in the Cook Inlet-Susitna Region, South-Central Alaska

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Abstract

The Cook Inlet-Susitna region of south-central Alaska contains large quantities of gas-bearing coal of Tertiary age. The U.S. Geological Survey in 2011 completed an assessment of undiscovered, technically recoverable coal-bed gas resources underlying the Cook Inlet-Susitna region based on the total petroleum system (TPS) concept. The Cook Inlet Coal-Bed Gas TPS covers about 9,600,000 acres and comprises the Cook Inlet basin, Matanuska Valley, and Susitna lowland. The TPS contains one assessment unit (AU) that was evaluated for coal-bed gas resources between 1,000 and 6,000 feet in depth over an area of about 8,500,000 acres.

Coal beds, which serve as both the source and reservoir for natural gas in the AU, were deposited during Paleocene–Pliocene time in mires associated with a large trunk-tributary fluvial system. Thickness of individual coal beds ranges from a few inches to more than 50 feet, with cumulative coal thickness of more than 800 feet in the western part of the basin. Coal rank ranges from lignite to subbituminous, with vitrinite reflectance values less than 0.6 percent throughout much of the AU.

The AU is considered hypothetical because only a few wells in the Matanuska Valley have tested the coal-bed reservoirs, so the use of analog coal-bed gas production data was necessary for this assessment. In order to estimate reserves that might be added in the next 30 years, coal beds of the Upper Fort Union Formation in the Powder River Basin of Wyoming and Montana were selected as the production analog for Tertiary coal beds in the Cook Inlet-Susitna region. Upper Fort Union coal beds have similar rank (lignite to subbituminous), range of thickness, and coal-quality characteristics as coal beds of the Tertiary Kenai Group. By use of this analog, the mean total estimate of undiscovered coal-bed gas in the Tertiary Coal-Bed Gas AU is 4.674 trillion cubic feet (TCF) of gas.

Introduction

The U.S. Geological Survey (USGS) in 2011 completed an assessment of undiscovered, technically recoverable, conventional and unconventional oil and gas resources in the Cook Inlet-Susitna region of south-central Alaska. The assessment is based on the total petroleum system (TPS) concept (Schmoker, 2005) and includes four assessment units (AU). Results of the complete assessment were reported by Stanley and others (2011). The purpose of this report is to provide a synthesis of the geology of the Cook Inlet-Susitna region and to present input parameters and results of the Cook Inlet Coal-Bed Gas TPS resource assessment.

Coal was first discovered in Alaska at Port Graham on the Kenai Peninsula by Russian explorers in 1786, although it was undoubtedly used by native Alaskans earlier (Merritt and Hawley, 1986). The Russian-American Company opened the first documented coal mine in Alaska in 1855 at this site, exporting 88 tons of coal to California in its first year (Davis, 1981; Merritt and Hawley, 1986). Since then, as much as 12 billion short tons of coal have been discovered in the Cook Inlet-Susitna region, with estimates of undiscovered or hypothetical coal resources at 1,600 billion short tons (Hopkins, 1951, *cited in* Flores and others, 2003; Barnes and Cobb, 1959; Barnes, 1967; Renshaw, 1983; Merritt and Belowich, 1984; Merritt and Hawley, 1986; Affolter and Stricker, 1987).

Production of gas from conventional sandstone and conglomerate reservoirs began in 1958, and more than 7.8 trillion cubic feet (TCF) have been produced (Alaska Department of Natural Resources, Division of Oil and Gas, 2009). As much as 93 percent of the natural gas discovered to date may have been sourced from coal interbedded with the conventional sandstone and conglomerate reservoirs (Claypool and others, 1980). Geochemical evidence suggests that most of the coal-bed-sourced gas in Cook Inlet conventional accumulations is biogenic rather than thermogenic, because biogenic gas generated from coal beds is isotopically light ($\delta^{13}C$ range of –63 to –56 per mil) and chemically dry ($C_1/C_{1-5} > 0.99$; Claypool and others, 1980).

The large amount of coal in the Cook Inlet-Susitna region, coupled with moderate to good gas content, suggests the potential for a large untapped coal-bed gas resource. Although no official estimates of coal-bed gas resources in the Cook Inlet-Susitna region have been published previously by the USGS, a total gas-in-place resource of 245 TCF was estimated by Montgomery and Barker (2003).

Structural and Tectonic Setting

The Cook Inlet basin is a northeast-southwest trending fore-arc basin flanked by the Aleutian volcanic arc to the northwest and Chugach-Kenai accretionary complex to the southeast and bounded by active high-angle reverse fault zones (fig. 1). The Castle Mountain and Bruin Bay fault zones make up the northern and northwestern boundaries, separating the uplifted volcanic arc complex from the basin. The southeastern boundary is defined by the Border Ranges fault, which separates the basin from the Chugach terrane.

Basin accommodation for more than 25,000 feet (ft) of Tertiary nonmarine strata is attributed to early Tertiary deformation and increased tectonism associated with the subduction of the Kula plate and spreading center in the Early Eocene (fig. 2) (Byrne, 1979, *cited in* Swenson, 1997; Pavlis, 1982). Tertiary strata are thickest in the basin center and thin towards the basin margins (fig. 3). Rapid subsidence and deposition of nonmarine sand, organic matter, and silt continued until the end of the Pliocene, when the latest phase of tectonism deformed the basin margins.

Numerous fault-cored folds related to this latest phase of tectonism are present in the Cook Inlet, with fold axes that are generally subparallel to the margins of the basin and trend northeast-southwest (Plafker and others, 1994). These folds are generally asymmetric and doubly plunging, with opposing sense of vergence, and are thought to be developed by right-transpressional deformation on oblique-slip faults extending downward into Mesozoic basement (Nokleberg and others, 1994; Haeussler and others, 2000). Right-transpressional deformation of the Cook Inlet likely is driven by a combination of subduction of the Pacific plate and lateral escape of the fore arc to the southwest resulting from the collision of the Yakutat block to the east of the basin (Haeussler and others, 2000). Much of the exploration and production activity in the Cook Inlet basin to date has focused on the fault-cored folds.

The Susitna lowland (fig. 1) is considered the northern extension of the Cook Inlet basin, located between the Talkeetna Mountains to the east and the Alaska Range to the north and west (Miller and Dobrovolny, 1959; Smith, 1995). The Susitna arch, a partially buried ridge of granitic rocks near the Castle Mountain fault zone, separates the shallower and younger Susitna lowland from the Cook Inlet basin (Kelly, 1963; Smith, 1995).

The Matanuska Valley is considered the northeastern arm of the Cook Inlet basin, forming a structural trough 8 to 16 kilometers (km) wide and 80 km long that narrows to the northeast (Merritt and Belowich, 1984). The valley is between the Talkeetna Mountains to the north and Chugach Mountains to the south. The Castle Mountain fault to the north and an unnamed fault zone to the south separate Tertiary and Cretaceous rocks of the Matanuska Valley from older and more highly deformed metamorphic and intrusive rocks of the mountains (Barnes and Payne, 1956). Deformation of coal-bearing rocks and abundance of igneous dikes and sills increase eastward, resulting in coals that are strongly folded and faulted and of higher rank compared to coals of the Cook Inlet and Susitna lowland (Merritt and Belowich, 1984; Stricker, 1991).

Stratigraphic Framework

Tertiary nonmarine, coal-bearing basin fill unconformably overlies deeply buried, mostly marine Mesozoic rocks (fig. 4). Six regional, time-transgressive units were defined on the basis of “type” well logs by Calderwood and Fackler (1972). These units are thought to contain laterally equivalent facies related to a dynamic nonmarine depositional system (Swenson, 1997). The coarsest facies (conglomerates and sandstones) were deposited near the source by an alluvial fan system that drained the basin margins, while a distal axial-fluvial system in the center of the basin reworked the alluvial fan deposits (Flores and others, 2004) (fig. 5). Coal deposits accumulated in mires related to this large fluvial drainage system.

Lower Tertiary Rocks

Lower Tertiary rocks in the Cook Inlet-Susitna region include the Paleocene–Eocene Chickaloon Formation and Eocene Wishbone Formation. The Chickaloon Formation is present in the northeastern part of the basin and crops out in the Matanuska Valley. This formation consists of a 3,300- to 4,900-ft-thick sequence of mudstone, siltstone, and sandstone, with minor conglomerate and coal (Triplehorn and others, 1984; Flores and Stricker, 1993). Sandstone beds are erosionally based and range from lenticular to tabular in geometry. As many as 12 coal beds have been reported in the Chickaloon Formation. Coal beds are lenticular and vary in thickness within 300 ft laterally. Individual coal beds average less than 3 ft in thickness, but a coal bed more than 15 ft thick has been reported in the Chickaloon mine (Wahrhaftig and others, 1994). Coal rank increases from west to east within the Matanuska Valley, from high-volatile subbituminous to semianthracite. This increase in rank is attributed to heating of the coal by the abundant igneous dikes and sills within the Chickaloon Formation in the eastern Matanuska Valley (Merritt, 1985; Stricker, 1991; Wahrhaftig and others, 1994).

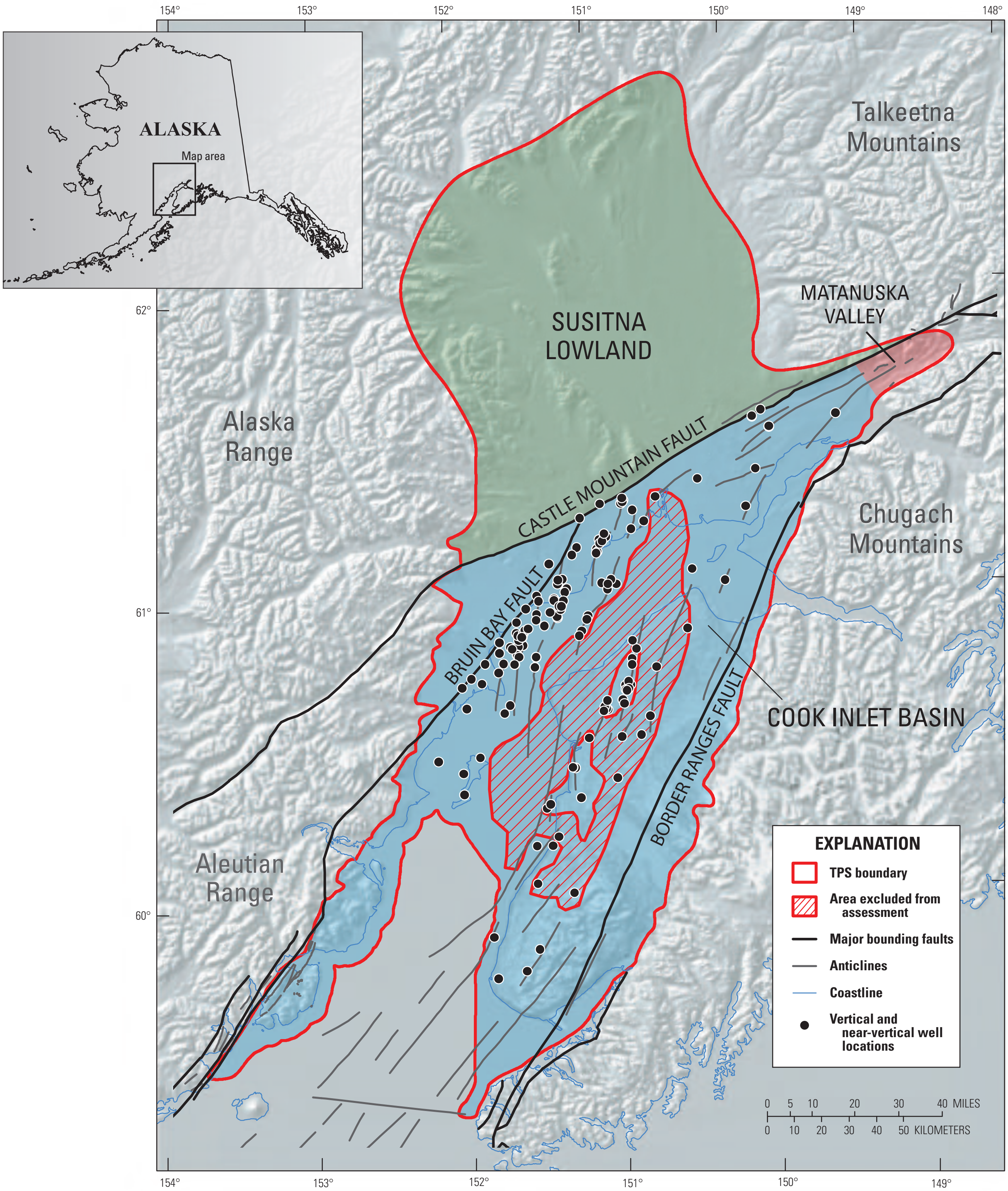

Figure 1. Location of the Cook Inlet Coal-Bed Gas Total Petroleum System (TPS), major bounding faults, anticlines, and vertical and near-vertical well locations within the Cook Inlet-Susitna region, south-central Alaska. The Coal-Bed Gas Assessment Unit (AU) excludes an area in the center of the Cook Inlet basin where the principal coal-bearing units are deeper than 6,000 feet and are unlikely to be productive of gas. An area (not shown) around the outer perimeter of the AU where the principal coal-bearing units are shallower than 1,000 feet also is excluded from the assessment.

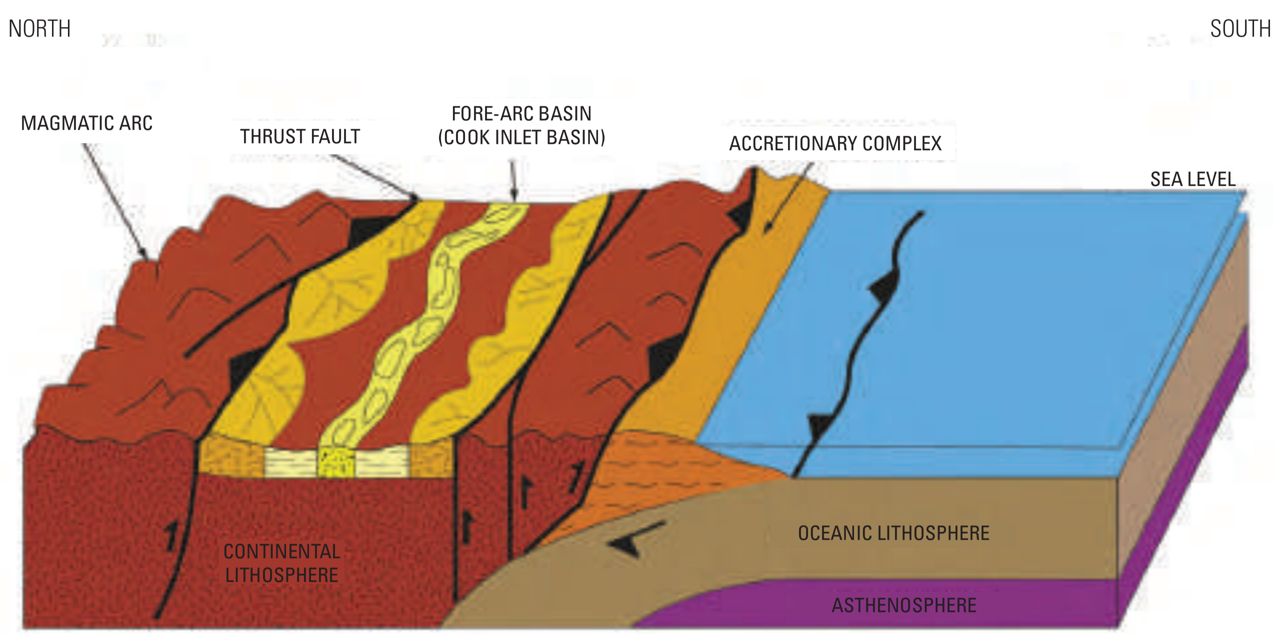

Figure 2. Tectonic and volcanic settings of the Cook Inlet basin (Flores and others, 2004; modified from Swenson, 1997).

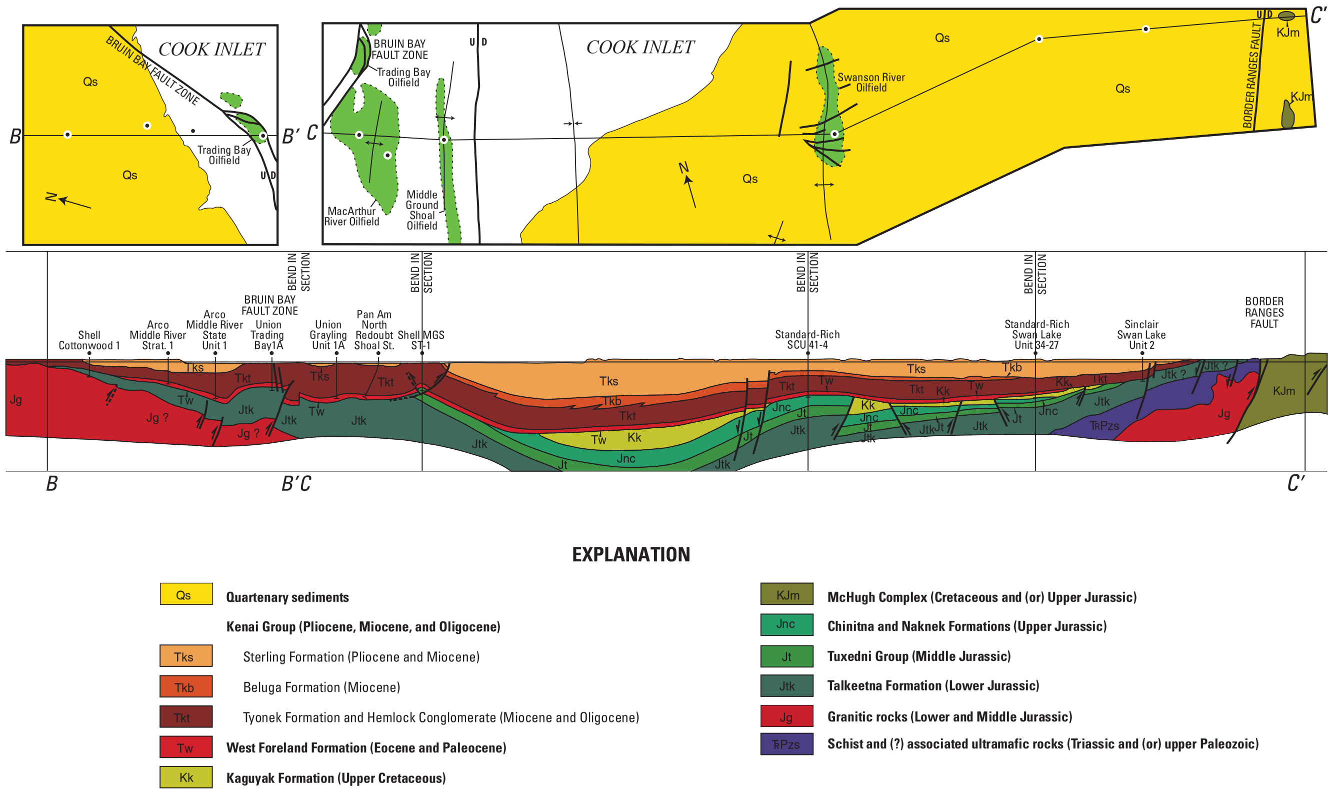

Figure 3. Cross section of the eastern Aleutian Arc, from Mount Spurr to the Border Ranges fault, Alaska (modified from Plafker and others, 1982).

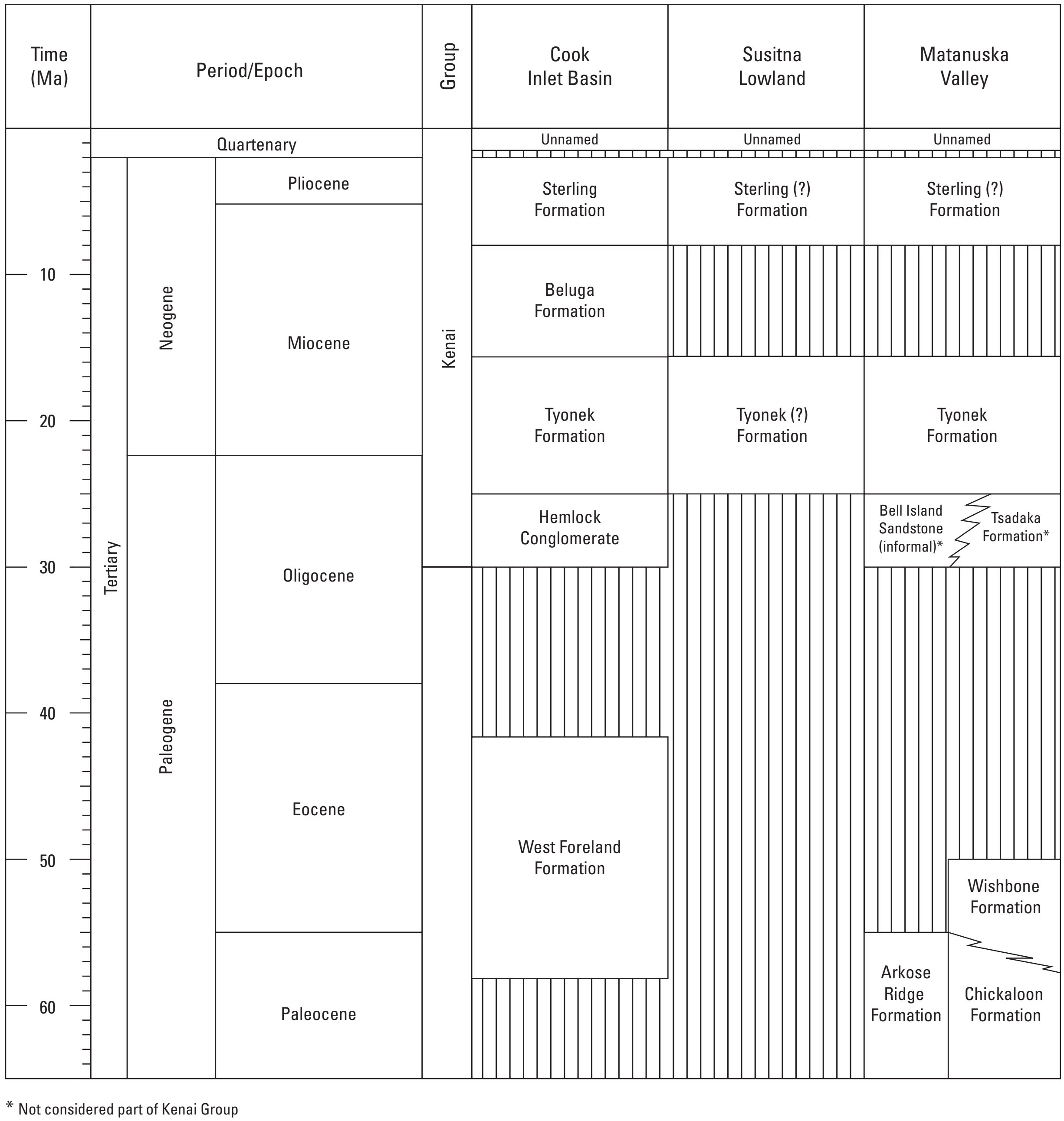

Figure 4. Tertiary correlation chart for the Cook Inlet-Susitna region (modified from Wahrhaftig and others, 1994; formations in Susitna lowland from Reed and Nelson, 1980). See Swenson (1997) for interpretation of interfingering relations in Tertiary Strata. (Ma, million years before present.)

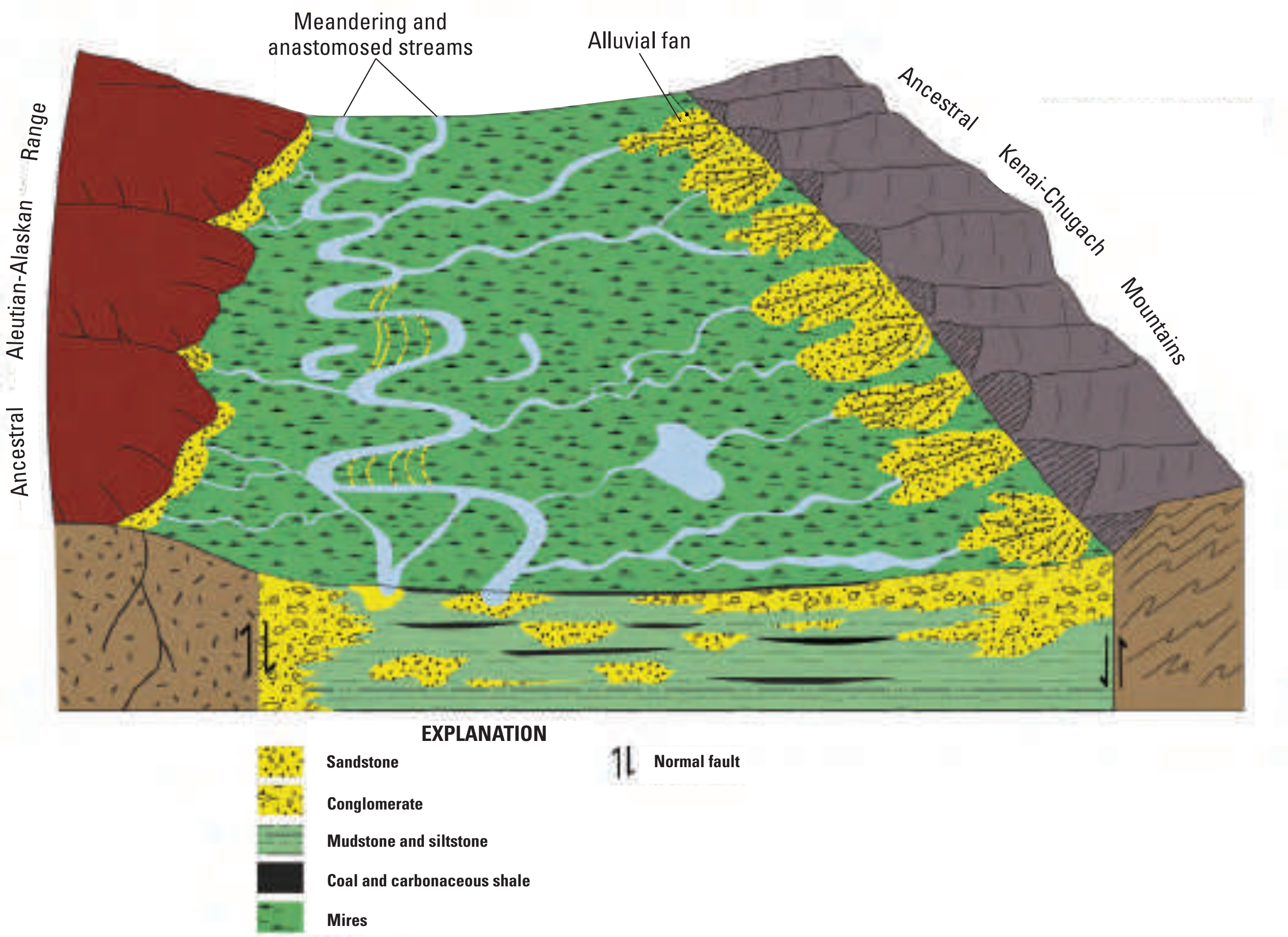

Figure 5. Depositional model of the Kenai Group in the Cook Inlet basin (Flores and others, 2004; modified from Hayes and others, 1976).

The Chickaloon Formation unconformably overlies the Lower and Upper Cretaceous Matanuska Formation, which consists of marine sandstone and shale (Barnes and Payne, 1956; Grantz and Jones, 1960) and is overlain unconformably by the Eocene Wishbone Formation.

The Wishbone Formation consists of 3,000 ft of thick, massive conglomerate and sandstone containing clasts that indicate a provenance in the Talkeetna Mountains to the north. The formation is restricted to the Matanuska Valley and is unconformably overlain by flat-lying Tertiary basalt at the east end of the Matanuska coal field. The Wishbone Formation correlates with the West Foreland Formation in the Cook Inlet basin (Wahrhaftig and others, 1994; Flores and others, 2004).

The West Foreland Formation consists of 2,000 ft of tuffaceous claystone, sandstone, and conglomerate, with a few thin coals. The formation underlies most of the lower Cook Inlet basin southwest of the mouth of the Susitna River and much of the lowland area of the northwestern Kenai Peninsula (Hartman and others, 1971).

The Wishbone and West Foreland Formations are overlain by the Oligocene–Pliocene Kenai Group, though the nature of the contact has been the subject of debate. C.E. Kirschner (1989, written commun.; *cited in* Wahrhaftig and others, 1994), following the assignment of the West Foreland Formation as the basal unit of the Kenai Group by Calderwood and Fackler (1972), regarded the West Foreland Formation as conformable and probably continuous with the rest of the Kenai Group in the subsurface of the Cook Inlet basin. Kirschner suggested that an unconformity between the West Foreland Formation and parts of the Tyonek Formation observed along the margins of the Cook Inlet basin is spatially restricted to the margins of the basin; however, Magoon and others (1976) regarded the unconformity as regional, because sections of the West Foreland Formation that have been dated are 20 million years older than rocks of the Kenai Group. The USGS has adopted the interpretation of Magoon and others (1976) (Wahrhaftig and others, 1994).

Upper Tertiary Kenai Group

The Kenai Group comprises four formations: the Oligocene Hemlock Conglomerate, Oligocene–Middle Miocene Tyonek Formation, Upper Miocene Beluga Formation, and Upper Miocene–Pliocene Sterling Formation (Dall and Harris, 1892; Parkinson, 1962; Calderwood and Fackler, 1972). Most coal shallower than 6,000 ft in the Cook Inlet-Susitna region is in the Kenai Group (Montgomery and Barker, 2003).

The Oligocene Hemlock Conglomerate consists of pebble to boulder conglomerate containing clasts of quartz; chert; metamorphic, volcanic, and plutonic rock fragments; a few thin coal beds; and many siltstone beds. This formation, along with the temporally equivalent Bell Island Sandstone and Tsadaka Formation in the Matanuska Valley, forms a sheet deposit that ranges from 655 to 2,772 ft in thickness (Wolfe and Tanai, 1980; Magoon and Egbert, 1986). Sandstone reservoirs within the formation average 17 percent porosity and 80 millidarcy (md) permeability and represent the main producing horizon for oil in the offshore Cook Inlet (Magoon and Anders, 1990; Magoon, 1994).

The overlying Tyonek, Beluga, and Sterling Formations make up a thick sequence of alluvial sandstone, conglomerate, siltstone, mudstone, carbonaceous shale, and coal, with most of the coal in the Tyonek and Beluga Formations (Wahrhaftig and others, 1994). Sandstone beds are fine to coarse grained, thick, erosive based, crossbedded, and vertically stacked. Individual coal beds range in thickness from a few inches to more than 50 ft. Coal rank ranges from lignite in the Sterling Formation to subbituminous in the Tyonek Formation. Subsurface correlation of coal beds from well to well is difficult for distances of more than a mile, suggesting considerable lenticularity of the coal beds and intervening sedimentary rocks. In outcrop, however, individual coal beds have been traced for as far as 6.2 miles (Barnes, 1966; Ramsey, 1981).

Methodology

Interpretation of geophysical logs from 153 oil and gas exploration wells in the Cook Inlet-Susitna region was used to delineate coal-bed thickness and stratigraphic distribution in the subsurface (fig. 1). This study was limited to wells for which Log ASCII Standard (LAS) files were available. Only vertical and near-vertical wells (<500 meters (m) horizontally between surface and bottom-hole locations) with both gamma-ray and bulk density logs were included. Wells that met these criteria were only in the Cook Inlet basin, excluding the Matanuska Valley and Susitna lowland.

Coal beds are readily identified in geophysical logs because of their unique physical properties, including low natural radioactivity and low density. Coal generally exhibits low radioactivity on gamma-ray logs compared to other lithologies in a coal-bearing sequence. Sandstone, however, may have similar gamma-ray values, making identification of coal beds based solely on gamma-ray logs difficult and requiring the use of a supplemental log.

Coal density averages between 0.7 and 1.8 grams per cubic centimeter (g/cc) (Wood and others, 1983), significantly less than associated lithologies. This density contrast is easily recognized on bulk density logs, where coal exhibits low-density spikes (fig. 6). Whereas the bulk density log is capable of identifying thin coal beds, similar density spikes are recorded where the borehole diameter is enlarged as a result of washout. Caliper logs, which measure the diameter of a borehole, can be used to identify areas where low-density measurements may be false (fig. 6).

Net coal-bed thickness between depths of 1,000 and 6,000 ft was quantified as a mapping parameter (fig. 7); explanation for this depth interval is provided below. Coal beds were defined as having bulk density values less than 2 g/cc. Digital logs were analyzed by using an automated routine to calculate the thickness of strata with a bulk density less than 2 g/cc between depths of 1,000 ft and 6,000 ft. These results include borehole washout intervals. Wells that were characterized by intervals of false low density due to borehole washout were removed from net coal thickness calculations in order to prevent overestimates. Nevertheless, logs for most wells likely contain some false low-density values, resulting in overestimates of net coal thickness. Conversely, the lack of a bulk density log curve for any part of the 1,000- to 6,000-ft depth interval results in an underestimate of net coal thickness. Therefore, net coal thickness derived from log analysis is used as a general parameter to delineate sweet spots of coal-bed gas potential.

In addition to net coal thickness in the 1,000- to 6,000-ft depth interval, individual thick coal deposits were used to further delineate sweet spots of coal-bed gas potential (fig. 8). Individual thick coal deposits are defined as at least 25 ft of coal within a 100-ft interval of section. Wells that were removed from net coal thickness calculations because of borehole washout were manually checked to determine the presence and stratigraphic position of thick coal deposits.

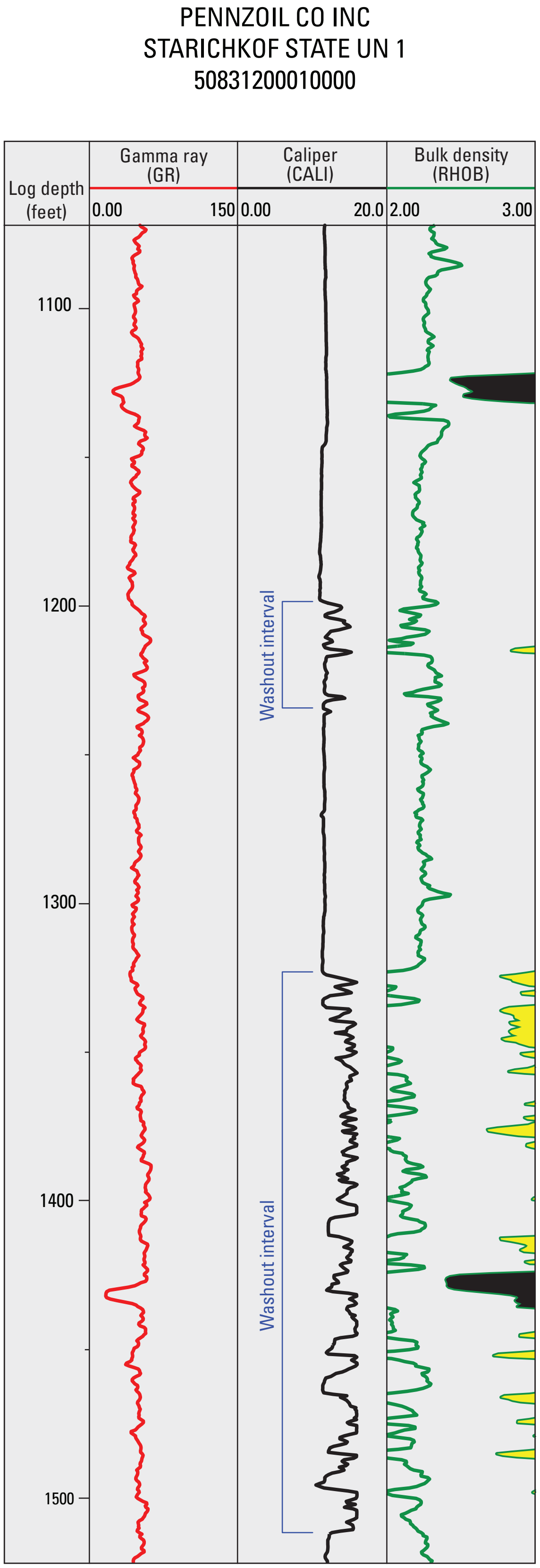

Figure 6. Well log response of coal and borehole washout intervals in the Starichkof State Unit 1 well. Coal beds (black) are identified by both low gamma-ray values (GR, red) and low-density response on the bulk density log curve (RHOB, green). Borehole washout intervals are identified on the caliper log (CALI, black). False low-density measurements associated with borehole washout intervals are highlighted on the bulk density log curve in yellow.

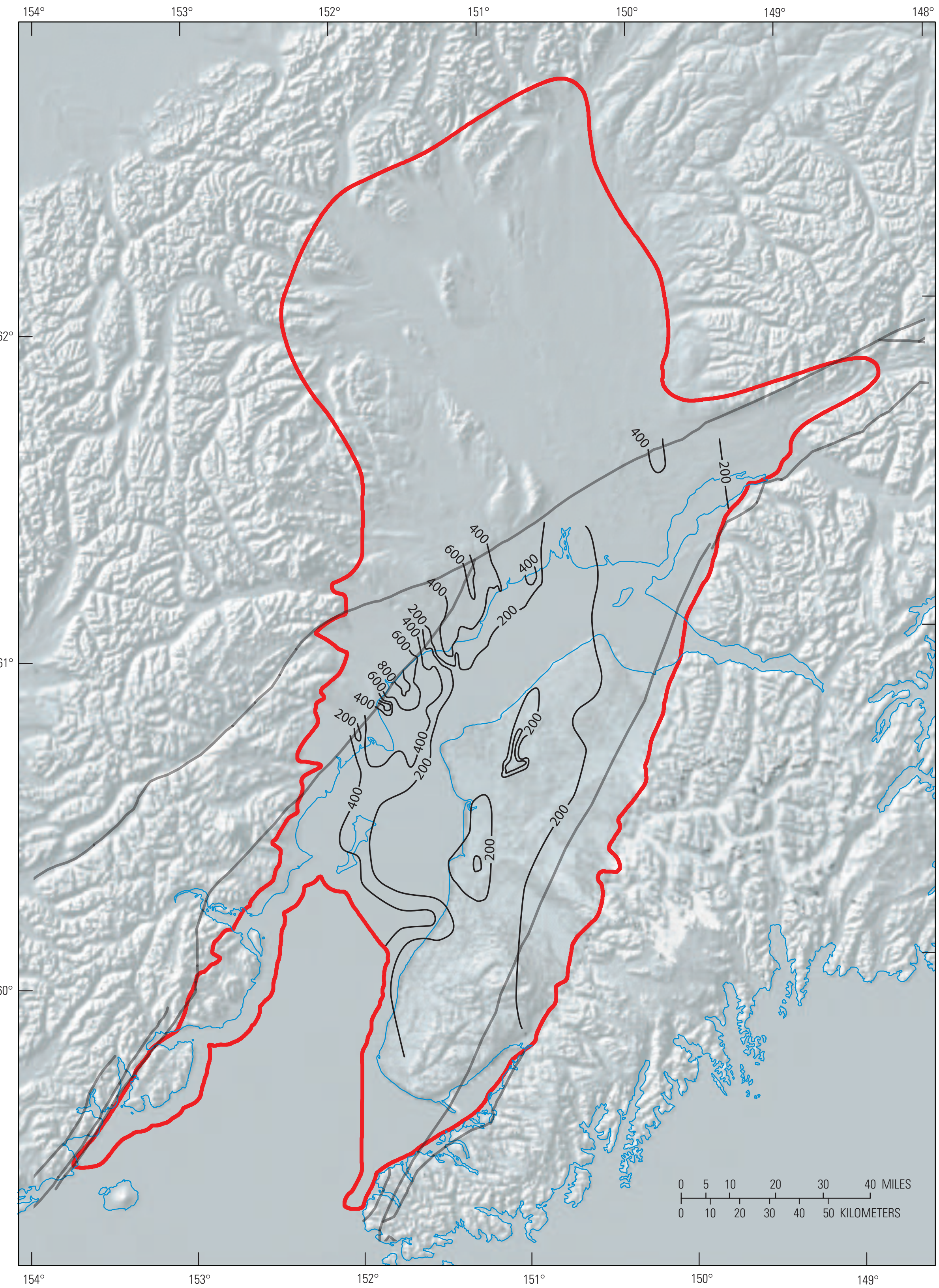

Figure 7. Cumulative thickness of coal (in feet) as inferred from records of wells between 1,000 and 6,000 feet deep in the Cook Inlet basin.

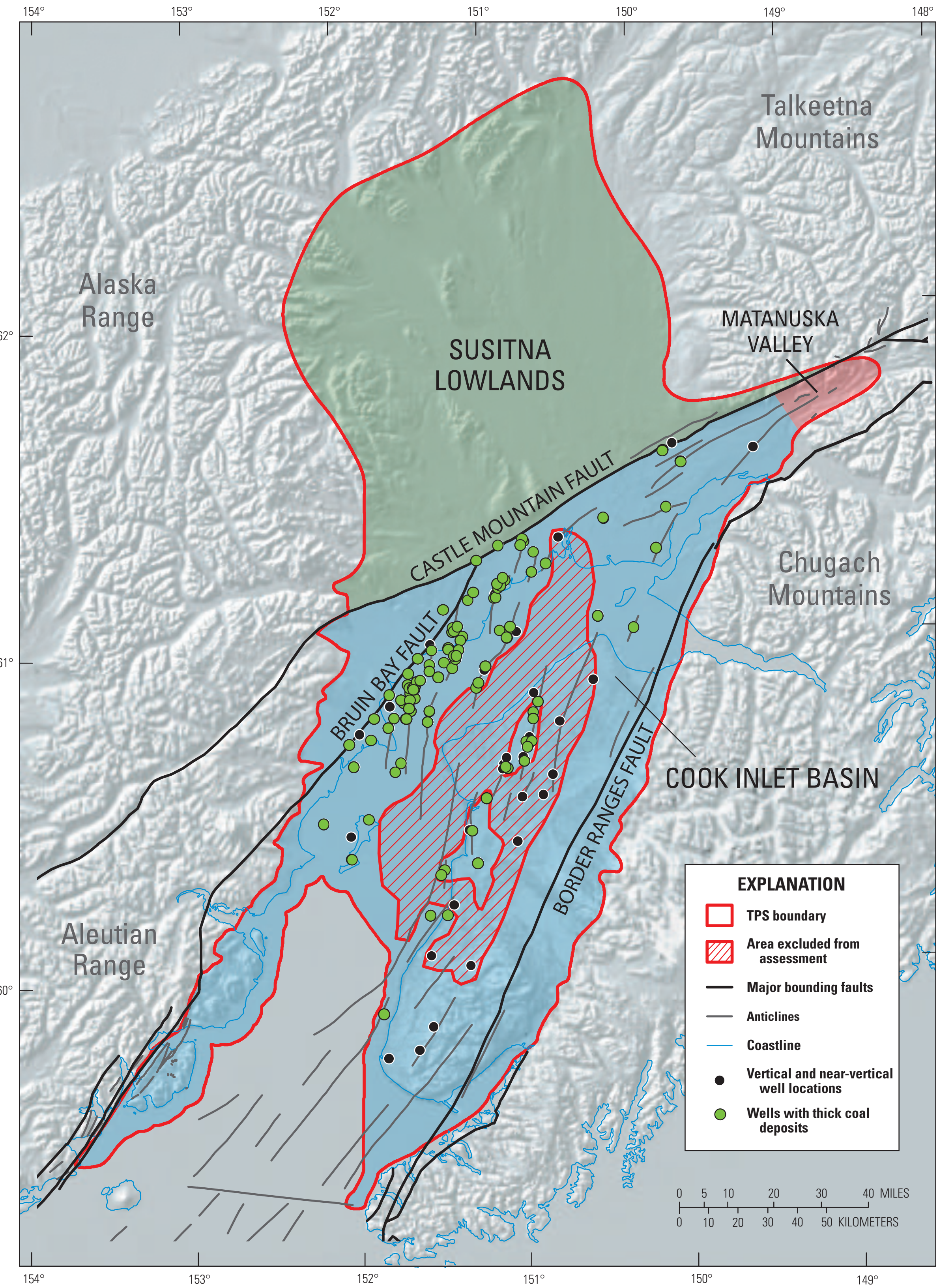

Figure 8. Location of wells with thick coal deposits between depths of 1,000 and 6,000 feet in the Cook Inlet basin. Thick coal deposits (green dots) are defined as at least 25 feet of coal within a 100-foot interval of section.

Total Petroleum System

Assessment of undiscovered, technically recoverable coal-bed gas resources of the Cook Inlet-Susitna region is based on the TPS concept (Schmoker, 2005). A TPS consists of all genetically related petroleum generated by a pod or closely related pods of mature source rocks. The Coal-Bed Gas TPS in the Cook Inlet-Susitna region comprises the Paleocene–Lower Eocene Chickaloon, Oligocene–Middle Miocene Tyonek, Upper Miocene Beluga, and Upper Miocene–Pliocene Sterling Formations, encompassing an area of about 9,600,000 acres. The TPS is divided into homogeneous subunits called assessment units, or AUs. Owing to similarities in lithology and abrupt lateral facies changes in the Chickaloon, Tyonek, Beluga, and Sterling Formations, it is difficult to determine precise and consistent stratigraphic contacts. Therefore, the TPS contains one continuous gas AU in Tertiary coal-bearing strata at depths between 1,000 and 6,000 ft. Coal beds generally lose permeability below 6,000 ft, and production levels are correspondingly uneconomic (McKee and others, 1986); at depths shallower than 1,000 ft, reservoir pressure in coals is assumed to be too low.

An area of approximately 1,100,000 acres within the central part of the Cook Inlet basin was excluded from the assessment because most coal deposits lie deeper than 6,000 ft (figs. 1 and 8). Owing to a paucity of well penetrations and limited seismic coverage, the area excluded from assessment was based mostly on the Mesozoic basement structure contour map (Shellenbaum and others, 2010) (fig. 9). The area excluded from the assessment roughly outlines that area of the basin where depth to basement is greater than 15,000 ft. The few wells within the zone excluded from the assessment contained no individual thick coal deposits.

An additional area along the perimeter of the AU also was excluded from assessment because coal deposits are likely to be shallower than 1,000 ft. A paucity of well data made it difficult to constrain this area, resulting in uncertainty in the assessment data input for the total assessment area (see “Assessment Data Input and Results”).

Source and Reservoir Rock

Coal beds within the TPS are the source of gas for both the coal and the conventional accumulations in sandstone reservoirs. Individual coal beds range from a few inches to more than 50 ft in thickness. Coal beds laterally merge, split, and pinch out as influenced by the intervening fluvial-channel sandstones. The net coal-thickness isopach shows that the thickest accumulations of coal between 1,000 and 6,000 ft in depth are along the west shore of the Cook Inlet. Broad areas contain more than 400 ft of net coal, with more than 800 ft locally (fig. 7). Net coal thickness decreases eastward over a 5- to 10-mile distance, and much of the basin contains less than 200 ft of net coal (fig. 7). At least one thick coal deposit between 1,000 and 6,000 ft depth is found in most of the area of the AU (fig. 8).

Maturation

Thermal maturity of the Cook Inlet-Susitna region was characterized by using published vitrinite reflectance (VR) data from 251 well and outcrop locations (fig. 10). VR in outcrops and the shallow subsurface ranges mostly from 0.18 to 4.18 percent, with values greater than 0.6 percent in the southwestern and northeastern parts of the basin. High reflectance values in the northeastern Matanuska Valley are attributed to tectonic deformation and magmatism along the Aleutian volcanic arc (Flores and others, 2003). The central part of the Cook Inlet basin and Susitna lowland maintains reflectance values of less than 0.6 percent, likely a function of low thermal conductivity related to the rapid rate of subsidence and sedimentation in these areas (Flores and others, 2004). Johnsson and others (1993) determined a similar basin-wide variation in thermal maturity from VR at 30 offshore and onshore wells in the Cook Inlet basin.

VR indicates that most coal beds in the Kenai Group are thermally immature (<0.6 percent reflectance (R_o)), owing to the very low VR gradient with depth (Johnsson and others, 1993). These thermally immature coals range from lignite to subbituminous and are the lowest ranks from which commercial gas is produced in the United States (Flores, 2004).

Claypool and others (1980) identified two types of natural gas occurrences in the Cook Inlet basin separated both stratigraphically and compositionally from each other, suggesting different origins:

- Gas produced from reservoirs sourced from coal beds is both isotopically light ($\delta^{13}C$ range of –63 to –56 per mil) and chemically dry (C_1/C_{1-5} > 0.99; Claypool and others, 1980). Claypool and others (1980) favored a biogenic origin for gas associated with Tertiary coal beds on the basis of low thermal maturity and isotopically light and chemically dry gas composition.

- VR of coals in the Chickaloon and lower Tyonek Formations in the Matanuska Valley is greater than 0.6 percent R_o, indicating a more mature thermal history. These thermally mature coals range from bituminous to semianthracite in rank. Gas recovered from lower Tyonek Formation coals in the Matanuska Valley is isotopically heavier ($\delta^{13}C$ range of –48.9 to –44.0 per mil) than shallow gas of the central and southern Cook Inlet. Given the high-temperature history and heavier gas composition, thermogenic gas is likely in coals in the Matanuska Valley (Smith, 1995, *cited in* Montgomery and Barker, 2003; Seamount and others, 1997; Barker and others, 2001).

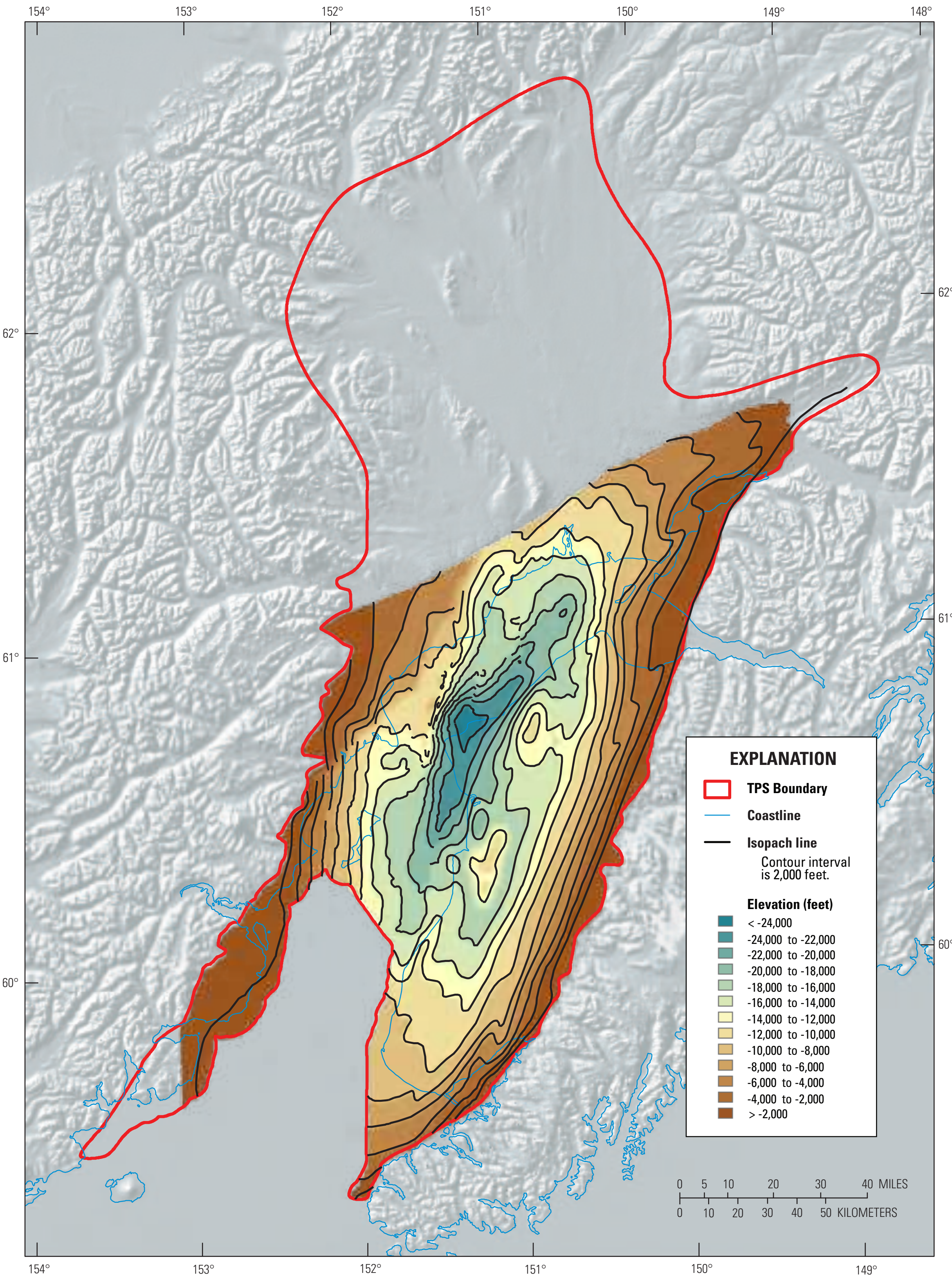

Figure 9. Structure contour map of the top of the Mesozoic basement, Cook Inlet basin (modified from Shellenbaum and others, 2010).

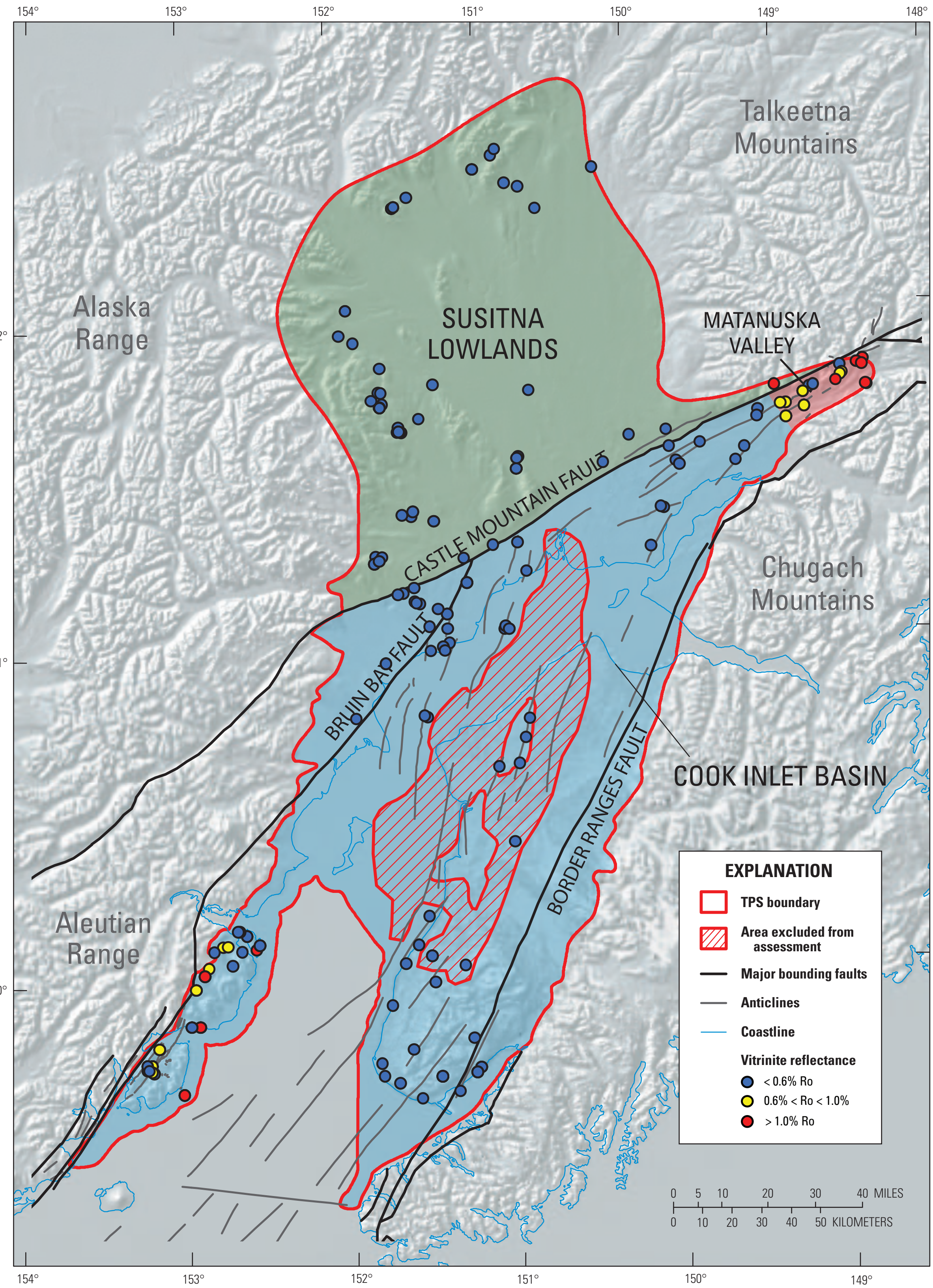

Figure 10. Outcrop and well vitrinite reflectance values within the Coal-Bed Gas Total Petroleum System (TPS) in the Cook Inlet-Susitna region. Vitrinite reflectances from well data are limited to the shallowest data at each well.

Reservoir Rock

Coal beds are inferred to serve as both source and reservoir rocks in the Cook Inlet Coal-Bed Gas AU. Coal-bed gas is produced in place and is adsorbed to coal surfaces along fractures, cleats, and pores (Flores, 2004). The amount of gas that coal can store is a function of coal rank, temperature, and pressure (Flores, 2004). Higher rank and pressure generally increase storage capacity, whereas higher temperature decreases storage capacity. Average gas content from canister desorption measurements on subbituminous coal in the central and southern Cook Inlet basin is 60 standard cubic feet per ton (scf/ton), whereas higher rank bituminous coal of the Matanuska Valley has an average gas content of 230 scf/ton (Barker and others, 2001).

Assessment Data Input and Results

The basic input data used for the assessment of Tertiary coal-bed gas in the Cook Inlet-Susitna region are listed in table 1. The AU is considered hypothetical because no production has been established from Tertiary coal-bed reservoirs, so the use of coal-bed gas analogs from the 48 contiguous States was necessary for this assessment. Coal beds of the Upper Fort Union Formation in the Powder River Basin of Wyoming and Montana were selected as a baseline production analog for Tertiary coal beds in the Cook Inlet-Susitna region. Upper Fort Union coal beds have the same rank (lignite to subbituminous) and similar coal-quality characteristics to coal beds of the Tertiary Kenai Group (Flores, 2004). Although coals of higher rank and greater gas storage capacity have been documented in the northeastern Matanuska Valley, they were not considered separately because (1) they are thought to be spatially limited to an area along the northeastern part of the Castle Mountain fault, (2) the subsurface extent of the higher rank coals is poorly constrained, and (3) their reservoir properties are thought to be influenced by strain related to the Castle Mountain fault and contact metamorphism by igneous dikes and sills (Barnes, 1962; Merritt, 1985; Stricker, 1991; Wahrhaftig and others, 1994).

The Tertiary Coal-Bed Gas AU is considered to have a minimum estimated ultimate recovery (EUR) per cell of 0.02 billion cubic feet of gas (BCFG) in this assessment. The assessment area contains an estimated minimum of 8,000,000 acres, mode of 8,500,000 acres, and maximum of 9,000,000 acres because of uncertainties in geologic map boundaries (table 1). The drainage area of untested cells having potential for additions to reserves is estimated at a minimum of 40 acres, a mode of 80 acres, and a maximum of 140 acres (table 1), values similar to those estimated for the Upper Fort Union Formation AU (Flores, 2004). All of the AU area is untested (table 1). The fraction of total AU area that has potential for additions to reserves in the next 30 years is estimated at a minimum of 0.5 percent, a mode of 6 percent, and a maximum of 63 percent (table 1). The mode percentage is based on the area of thick coal accumulation between 1,000 and 6,000 ft in depth near the western shore of the Cook Inlet relative to the total AU area. The minimum and maximum percentages reflect considerable uncertainty that stems from the absence of subsurface penetrations that meet the assessment criteria in more than 30 percent of the assessment unit (Susitna lowland and Matanuska Valley). The total recovery per cell for untested cells having potential for addition to reserves in the next 30 years was estimated at a minimum of 0.02 BCFG, a median of 0.16 BCFG, and a maximum of 1.5 BCFG (table 1). Using these inputs, the USGS estimates the total undiscovered coal-bed gas resources in the Cook Inlet-Susitna region as follows: 1,581 BCFG at F_{95}, 3,989 BCFG at F_{50}, and 10,069 BCFG at F_5; the mean estimate is 4,674 BCFG (table 2).

Table 1. Assessment data input for the Cook Inlet Coal-Bed Gas Assessment Unit.

NUMBER OF UNTESTED CELLS WITH POTENTIAL FOR ADDITIONS TO RESERVES

1. Total assessment-unit area (acres): (uncertainty of a fixed value)

calculated mean	8,500,000	minimum	8,000,000	mode	8,500,000	maximum	9,000,000

2. Area per cell of untested cells having potential for additions to reserves (acres): (values are inherently variable)

calculated mean	87	minimum	40	mode	80	maximum	140
uncertainty of mean:		minimum	40	maximum	120		

3. Percentage of total assessment-unit area that is untested (percent): (uncertainty of a fixed value)

calculated mean	100	minimum	100	mode	100	maximum	100

4. Percentage of untested assessment-unit area that has potential for additions to reserves (percent):
(a necessary criterion is that total recovery per cell ≥ minimum; uncertainty of a fixed value)

calculated mean	23	minimum	0.5	mode	6	maximum	63

TOTAL RECOVERY PER CELL

Total recovery per cell for untested cells having potential for additions to reserves:
(values, in billion cubic feet of gas, are inherently variable)

calculated mean	0.206	minimum	0.02	median	0.16	maximum	1.5

Table 2. Summary of results for risked, undiscovered, technically recoverable contiguous gas resources for the Cook Inlet Coal-Bed Gas Assessment Unit.

[BCFG, billion cubic feet of gas. Undiscovered gas resources are the sum of nonassociated and associated gas. F_{95} represents a 95-percent chance of at least the amount tabulated; other fractiles are defined similarly]

Assessment unit name	Total undiscovered gas resources (BCFG)			
	F_{95}	F_{50}	F_5	Mean
Cook Inlet Coal-Bed Gas	1,581	3,989	10,069	4,674

Summary

The Cook Inlet Coal-Bed Gas Total Petroleum System (TPS) of south-central Alaska comprises coal-bearing Tertiary strata of the Cook Inlet basin, Matanuska Valley, and Susitna lowland. The TPS contains one hypothetical assessment unit (AU) that was evaluated for coal-bed gas resources between 1,000 and 6,000 ft in depth over an area of about 8,500,000 acres. Coal beds, which range in thickness from a few inches to more than 50 ft, were deposited in mires associated with a large trunk-tributary fluvial system. Gas associated with the lignite to subbituminous coal in the AU is likely biogenic in origin. Potential for addition to reserves in the next 30 years is greatest along the western part of the Cook Inlet basin, where cumulative coal thickness exceeds 800 ft. Using coal beds of the Upper Fort Union Formation in the Powder River Basin of Wyoming and Montana as a baseline production analog, the USGS estimates the total undiscovered coal-bed gas resources in the Cook Inlet Coal-Bed Gas AU as follows: 1,581 BCFG at F_{95}, 3,989 BCFG at F_{50}, and 10,069 BCFG at F_5; the mean estimate is 4,674 BCFG (table 2).

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USGS

Rouse and Houseknecht—**Assessment of the Coal-Bed Gas Total Petroleum System in the Cook Inlet-Susitna Region, Alaska**—Scientific Investigations Report 2012-5145

Assessment of Undiscovered Oil and Gas Resources of the Susitna Basin, Southern Alaska, 2017

The U.S. Geological Survey (USGS) recently completed an assessment of undiscovered, technically recoverable oil and gas resources in the Susitna Basin of southern Alaska. Using a geology-based methodology, the USGS estimates that mean undiscovered volumes of about 2 million barrels of oil and nearly 1.7 trillion cubic feet of gas may be found in this area.

Introduction

The Susitna Basin is a sparsely inhabited region of forested hills and flatlands, situated in southern Alaska about 50 miles (80 kilometers) from Alaska's largest city, Anchorage (figs. 1 and 2). U.S. Geological Survey (USGS) scientists recently finished their first detailed assessment of the undiscovered oil and gas potential of the Susitna Basin at a time when there is significant interest in natural gas supplies of the Anchorage metropolitan area, where natural gas is the principal source of energy for heating and electric power generation in the region.

No commercial petroleum production has been obtained from the Susitna Basin. Few exploratory wells have been drilled, and most of the area is completely unexplored for oil and gas. However, a USGS review of all available geological information from the Susitna Basin indicates the probable existence of technically recoverable oil and gas resources—in other words, those that can be discovered, developed, and produced using current technology—in rocks of Tertiary age (about 66 to 2.6 million years old). The USGS review was done in cooperation with the State of Alaska Department of Natural Resources and included geological field investigations, exploratory wells, seismic data, and gravity and aeromagnetic surveys.

The USGS assessment was based on the geologic elements used to define a Total Petroleum System, including

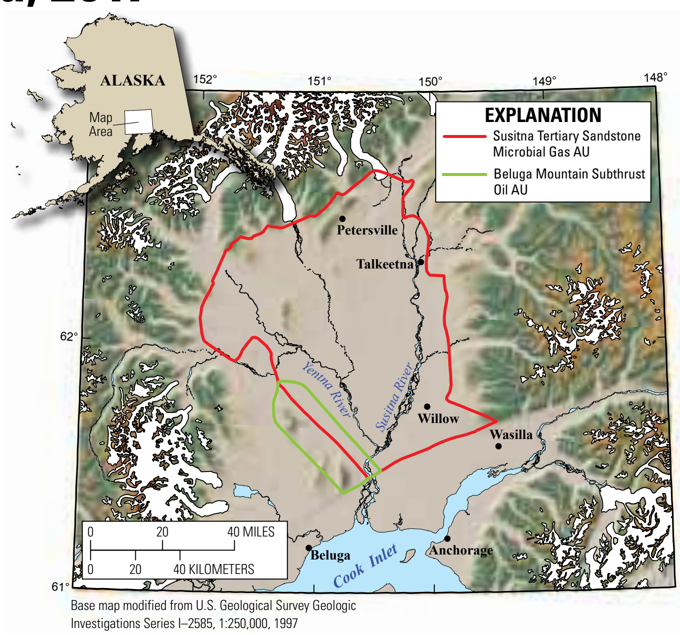

Figure 1. U.S. Geological Survey scientists have estimated undiscovered oil and gas resources within two assessment units (AUs) in the Susitna Basin of southern Alaska. This map shows the AU perimeters, which are based on geological criteria. White areas represent ice, whereas colors show elevations ranging from lowest (tan) to higher (green) to highest (dark brown).

characterization of hydrocarbon source rocks (distribution, thickness, organic richness, thermal maturation, and timing of petroleum generation and migration), reservoir rocks (distribution, quality, and time of formation), and hydrocarbon traps (character and time of formation).

Using this geologic framework, the USGS defined the Susitna Total Petroleum System and two assessment units

Figure 2. The 4,000-square-mile (10,300 square kilometer) Susitna Basin assessment area is characterized by low, forested hills and flatlands. This photograph, looking generally south at an area west of Willow, Alaska, shows a typical landscape. The prominent diagonal line is a remnant of a seismic reflection survey conducted by the oil industry in search of petroleum. Photograph by Richard G. Stanley, U.S. Geological Survey, June 21, 2011.

Figure 3. A 4-meter-thick layer of coal in an outcrop located west of Willow, Alaska. Layers of coal similar to this outcrop are possible source rocks of petroleum in the Susitna Basin. Photograph by Richard G. Stanley, U.S. Geological Survey, August 3, 2014.

(AUs) within it—the Susitna Tertiary Sandstone Microbial Gas AU and the Beluga Mountain Subthrust Oil AU. The likely petroleum source rocks in both AUs are coals and shales that are rich in organic matter (fig. 3). Undiscovered petroleum accumulations in both AUs may exist in sandstone and conglomerate reservoirs in structural traps (for example, on anticlines or adjacent to faults) and in stratigraphic traps (for example, where sandstone reservoirs that formed in ancient river channels are confined by impermeable, fine-grained strata that formed on the adjacent floodplains). Key data used to assess the AUs are listed in table 1.

Resource Summary

The USGS assessment provides forecasts of the volumes of undiscovered petroleum (mainly oil and natural gas) that are technically recoverable. For the Susitna Total Petroleum System, the USGS estimates that total undiscovered natural gas resources range between 0 and 4,672 billion cubic feet of gas (BCFG), with a mean estimate of 1,679 BCFG (table 2). About 99.8 percent, or 1,675 BCFG, of the mean natural gas estimate is expected to be found in conventional accumulations in the Susitna Tertiary Sandstone Microbial Gas AU, whereas about 0.02 percent, or 4 BCFG, is expected to be found in the Beluga Mountain Subthrust Oil AU.

The USGS estimates that total undiscovered oil resources in the Susitna Total Petroleum System range between 0 and 10 million barrels of oil (MMBO), with a mean estimate of 2 MMBO (table 2). All of the forecasted oil resources are expected to be found in conventional accumulations in the Beluga Mountain Subthrust Oil AU.

Susitna Basin USGS Assessment Team

Richard G. Stanley (Susitna Task Leader; rstanley@usgs.gov), Christopher J. Potter, Kristen A. Lewis, Paul G. Lillis, Anjana K. Shah, Peter J. Haeussler, Jeffrey D. Phillips, Zenon C. Valin, Christopher J. Schenk, Timothy R. Klett, Michael E. Brownfield, Ronald M. Drake, Thomas M. Finn, Seth Haines, Debra K. Higley, David W. Houseknecht, Phuong A. Le, Kristen R. Marra, Tracey J. Mercier, Heidi M. Leathers-Miller, Stanley T. Paxton, Ofori N. Pearson, Marilyn E. Tennyson, Cheryl A. Woodall, and Margarita V. Zyrianova.

For more information, contact:

USGS Energy Resources Program: https://energy.usgs.gov/

Edit and layout by Katherine Jacques, tables by Cory Hurd

Table 1. Key data for two conventional assessment units in the Susitna Basin of southern Alaska.

[AU, assessment unit; BCFG, billion cubic feet of gas; MMBO, million barrels of oil; -, not applicable]

Assessment input data	Minimum	Median	Maximum	Calculated mean
Susitna Tertiary Sandstone Microbial Gas AU				
Number of gas fields	1	40	264	47.9
Sizes of gas fields (BCFG)	3	10	2,500	40.7
AU probability	0.86	-	-	-
Beluga Mountain Subthrust Oil AU				
Number of oil fields	1	3	15	3.4
Sizes of oil fields (MMBO)	0.5	1.5	20	2.1
AU probability	0.27	-	-	-

Table 2. Assessment results for conventional oil and gas resources in the Susitna Basin of southern Alaska.

[AU, assessment unit; MMBO, million barrels of oil; BCFG, billion cubic feet of gas; NGL, natural gas liquids; MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas accumulations, all liquids are included in the NGL category. F95 represents a 95-percent chance of at least the amount tabulated; other fractiles (F) are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. -, not applicable]

Total petroleum system and assessment units	AU probability	Accumulation type	Total undiscovered resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
Susitna Total Petroleum System														
Susitna Tertiary Sandstone Microbial Gas AU	0.86	Gas	-	-	-	-	0	1,310	4,651	1,675	0	0	0	0
Beluga Mountain Subthrust Oil AU	0.27	Oil	0	0	10	2	0	0	21	4	0	0	0	0
Total undiscovered conventional resources	-	-	0	0	10	2	0	1,310	4,672	1,679	0	0	0	0

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Appendix B
Gary Player 2024 Documents
Prepared for Denali Petroleum and Gas Company

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Kenny Lake Ventures, LLC

August 27, 2018

Sterling–Here are a couple of references about CBM content in subbituminous coals, compared to potential Sand Bed Methane (Dissolved Gas) Resources.

Coalbed methane, Cook Inlet, south-central Alaska: A potential giant gas resource
American Association of Petroleum Geologists Bulletin, 2003
By: S.L. Montgomery and C.E. Barker

Abstract

Cook Inlet Basin of south-central Alaska is a forearc basin containing voluminous Tertiary coal deposits with sufficient methane content to suggest a major coalbed gas resource. Coals ranging in thickness from 2 to 50 ft (0.6 to 15 m) and in gas content from 50 to 250 scf/ton (1.6 to 7.8 cm2/g) occur in Miocene-Oligocene fluvial deposits of the Kenai Group. These coals have been identified as the probable source of more than 8 TCF gas that has been produced from conventional sandstone reservoirs in the basin.

Cook Inlet coals can be divided into two main groups:

(1) those of bituminous rank in the Tyonek Formation that contain mainly thermogenic methane and are confined to the northeastern part of the basin (Matanuska Valley) and to deep levels elsewhere;
(2) subbituminous coals at shallow depths (<5000 ft [1524 m]) in the Tyonek and overlying Beluga formations, which contain mainly biogenic methane and cover most of the central and southern basin.

Based on core and corrected cuttings-desorption analyses, **gas contents average** 230 scf/ton (7.2 cm2/g) for bituminous coals and **80 scf/ton (2.5 cm2/g) for subbituminous coals**. Isotherms constructed for samples of both coal ranks suggest that bituminous coals are saturated with respect to methane, whereas subbituminous coals at shallow depths along the eroded west-central basin margin are locally unsaturated. A preliminary estimate of 140 tcf gas in place is derived for the basin.

Typical Bulk Density of Coal
Anthracite Coal : 50 - 58 (lb/ft3), 800 - 929 (kg/m3)
Bituminous Coal : 42 - 57 (lb/ft3), 673 - 913 (kg/m3)
Lignite Coal : 40 - 54 (lb/ft3), 641 - 865 (kg/m3)

1671 W 546 S, Cedar City, UT 84720 T. (435) 590-8705
dirtdoctor43@gmail.com

Gas content of subbituminous coal is about 80 standard cubic feet (scf) per ton. Given an estimated density of subbituminous coal of 50 pounds per cubic foot, then a ton of coal is equal to 40 cubic feet of coal. Therefore, **each cubic foot of coal should release 2 standard cubic feet of methane.**

Assume that a coal bed 40 feet thick occupies 160 acres, or (43,560)*(160) = about 7 million square feet. If the coal averages 40 feet thick, the bulk volume of coal would be 280 million cubic feet. Therefore, the amount of CBM gas from a 40 feet thick bed of subbituminous coal covering 160 acres (1/4 of a section) would be twice the volume of the coal, or 560 million cubic feet, or 560,000 MCF.

In comparison, the likely SBM resource in 160 acres from 500 feet of Sterling sands with 34% porosity would be:
Aquifer volume = (160)*(500)*(.34) = 27,200 acre-feet, or 211,075,760 barrels of water.
With a GWR of 20, the SBM resource would be 4.22 billion cubic feet (BCF), or 4.22 million MCF.
That amount is 7.5 times the amount of CBM in the same 160 acres from one bed of coal, 40 feet thick.

The SBM could be recovered from 500 feet of slotted liner in one 5,000 feet deep vertical well, while the CBM would require at least four directional wells, each drilled about 1,200 feet horizontally from a central location in a quarter section. Some of the open slots in an SBM well would be across the coal bed, adding coal bed methane to the recovery.

Alaska Coal Geology, Resources, and Coalbed Methane Potential
Metadata Updated: June 8, 2018

Estimated Alaska coal resources are largely in Cretaceous and Tertiary rocks distributed in three major provinces. Northern Alaska-Slope, Central Alaska-Nenana, and Southern Alaska-Cook Inlet. Cretaceous resources, predominantly bituminous coal and lignite, are in the Northern Alaska-Slope coal province. Most of the Tertiary resources, mainly lignite to subbituminous coal with minor amounts of bituminous and semianthracite coals, are in the other two provinces. The combined measured, indicated, inferred, and hypothetical coal resources in the three areas are estimated to be 5,526 billion short tons (5,012 billion metric tons), which constitutes about 87 percent of Alaska's coal and surpasses the total coal resources of the conterminous United States by 40 percent. Coal mining has been intermittent in the Central Alaskan-Nenana and Southern Alaska-Cook Inlet coal provinces, with only a small fraction of the identified coal resource having been produced from some dozen underground and strip mines in these two provinces. Alaskan coal resources have a lower sulfur content (averaging 0.3 percent) than most coals in the conterminous United States (and) are within or below the minimum sulfur value mandated by the 1990 Clean Air Act amendments. The identified resources are near existing and planned infrastructure to promote development, transportation, and marketing of this low-sulfur coal.

The relatively short distances to countries in the west Pacific Rim make them more exportable to these countries than to the lower 48 States of the United States. Another untapped but potential resource of large magnitude is coalbed methane, which has been estimated to total 1,000 trillion cubic feet (28 trillion cubic meters) by T.N. Smith 1995, Coalbed methane potential for Alaska and drilling results for the upper Cook Inlet Basin: Intergas, May 15 - 19, 1995, Tuscaloosa, University of Alabama, p. 1 - 21.

Note: this reference estimates Alaska's CBM resources at an average value of:
(1,000 TCF/5,526 billion tons) = **181 scf (standard cubic feet) of methane per ton of coal.** That value is equal to the estimate for low rank bituminous coals from the first reference.

These are general estimates, but within the ball park of what we know.

I included the second reference just to show that all of the CBM throughout Alaska is less than the SBM resources I predicted for onshore portions of Cook Inlet basin in my May, 2017 talk to the AAPG convention in Anchorage.

Respectfully Submitted,

Gary F. Player

Gary F. Player
AAPG Member NO. 315235
Utah Professional Geologist No. 5280804-2250

Kenny Lake Ventures, LLC

Subject: Susitna Basin Dissolved Gas Prospect
Date: April 17, 2024

Introduction
Dry gas shortages in the stranded market of Anchorage, Alaska--now estimated to be at 50 percent or more of the market--can be replaced by a substantial resource of dissolved gas for electrical generation, domestic use and eventual export throughout Alaska. Construction of numerous wells, each capable of supplying approximately 400 MCF to 2,000 MCF per day, will quickly solve gas shortages for Anchorage and other Cook Inlet Basin towns.

Commercial Usage of Produced Dissolved Gas
Dissolved gas wells will provide a new method for producing natural gas in Alaska. Relatively shallow wells (3,000 to 8,000 feet below ground level) are drilled with conventional equipment and completed similarly to agricultural wells. Horizontal drilling and "fracking" are not required, and environmental disturbance is minimized. Deep saline (non-potable) waters are pumped to the surface where dissolved gas readily comes out of solution at surface temperatures and pressures. All produced water and gas will be kept in sealed, low pressure pipelines and tanks that do not leak hydrocarbons (mostly methane) to the atmosphere. Gas is compressed and injected into pipelines for use, while the water is returned to the same deep layers of sand and sandstone aquifers from which it was produced. This important step prevents surface water pollution and land settlement that could be caused by the collapse of pore spaces in drained, loose sediments.

Proposed Development
Denali Petroleum and Gas Company will produce previously undeveloped resources of natural gas dissolved in non-potable groundwater. Successful initial implementation of dissolved gas production northwest of Willow, Alaska, will provide ample energy for Anchorage and the Matanuska-Susitna Borough. The first fifteen dissolved gas wells (twelve producers and three water disposal wells) can then be followed by construction of hundreds of new wells throughout prospective areas on State lands in the Susitna Flats. A significant advantage of dissolved gas exploration is that expensive geophysical studies are not required. In addition, the average cost of relatively shallow dissolved gas wells (8,000 feet or less) is less than half that of typical onshore exploratory wells. Mudlog data reviewed from each old dry hole in the Susitna Basin has shown that dissolved gas is present throughout the initial prospective area. To estimate the resources on only a portion of the State lands licensed northwest of Willow, the following values can be assumed:

Area = 500,000 acres (781.25 sections, or 21.7 Townships)
Net Sand Thickness = 5,000 feet
Average Porosity = 28%
Gas/Water Ratio = 25 cubic feet per 42 gallon barrel

The volume of water in the dissolved gas charged saline aquifers = (500,000*5,000*.28) acre-feet, or 700,000,000 acre-feet. Each acre-foot equals approximately 7,758.4 barrels. Therefore the volume of

659 S Ridge Road, Cedar City, UT 84720 T. (435) 862-0614
dirtdoctor43@gmail.com

water containing dissolved gas is at least 5.431 Trillion Barrels. If each barrel of produced water contains 25 cubic feet of dissolved gas at surface temperatures and pressures, the dissolved gas resource = (25)(5.431 Trillion) =

136 Trillion Cubic Feet (TCF) of Dissolved Gas.

If one well per section is permitted by the State, then the resource available to each well would be 136/781.25 = approximately .174 TCF, or 174 Billion Cubic Feet or 174 million MCF. Each well producing just 400 MCF per day of dissolved methane would produce approximately 144,000 MCF per year. At that rate, each well could produce for 1200 years.

If four wells were allowed per section, than each one of 3,125 wells could produce 400 MCF per day for about 300 years. At a likely low price of $8.50 per MCF, the annual gross value of gas from each well would be $1,241,000. **The initial wells can be drilled approximately 35 miles northwest of Willow in T. 22 N, R. 8 W.**

Company Mission Statement

Denali Petroleum and Gas Company will produce previously undeveloped resources of natural gas dissolved in non-potable groundwater. Our mission is to provide natural gas and associated geothermal waters for existing pipelines and utility companies, sequestration of carbon dioxide, and other local industrial applications that are now limited by gas shortages in the Cook Inlet basin and other Alaskan communities.

Successful initial implementation of the first 12 dissolved gas production wells northwest of Willow, Alaska, will provide 1,728,000 MCF per year. These first dissolved gas wells will then be followed by construction of hundreds of new wells. Numerous wells, each capable of supplying from 400 to 2,000 thousand cubic feet (MCF) per day, depending on rates of water production and the ratio of dissolved gas to water, will eventually provide low-cost energy to towns, and villages now forced to use expensive imported liquid fuels.

Company goals

Gas shortages in and near the stranded market of Anchorage, Alaska, will be replaced by a substantial surplus of gas for local use. Initial customers will be Enstar Pipeline, Matanuska Electric Association, Chugach Electric Association, and local utilities in Willow, Houston and Wasilla. Gas reserves in several old fields in Cook Inlet Basin have declined drastically and can no longer supply Anchorage's utilities without extensive storage of gas produced during the summer months. "Fracking" wells have not been successful in Cook Inlet, as the shale beds are relatively thin and soft compared to targets in Texas and other states. Production of dissolved gas from the Susitna Flats is our best option.

Gary F. Player

Gary F. Player, B.S. Stanford, M.A. UCLA
Utah Professional Geologist No. 5280804-2250
American Association of Petroleum Geologists Emeritus Member No. 351235

659 S Ridge Road, Cedar City, UT 84720 T. (435) 862-0614
dirtdoctor43@gmail.com

October 30, 2024

Memorandum

From: Gary F. Player, Senior Geologist for Denali Petroleum and Gas Company
To: Frank Avezac, President of Denali Petroleum and Gas Company
Subject: Dissolved Gas Likelihood in the Susitna Basin

Let me state that I have been studying the occurrences of dissolved gas since 1999. One of my most important trips was to Japan in 2001, where I was fortunate enough to visit the largest and longest living dissolved gas production facility in the world. I have also studied similar operations in Italy and the United States, convincing myself that my ideas have been successfully implemented by many others.

I have explored for and developed several dry gas accumulations in Cook Inlet Basin, Alaska and the San Joaquin Valley of California. Each of them is now depleted. The largest field I developed was the Kenai Gas Field for Union Oil Company. It yielded on the order of two Trillion Cubic Feet, but is now useful only as a large gas storage facility to help Anchorage get through each winter.

Every well drilled in lowlands adjacent to and north of the Castle Mountain Fault System (the southern boundary of the Susitna Basin) have shows of methane gas, usually dissolved in sand and sandstone aquifer systems beginning 1,500 to 2,000 feet below ground level. Shows are strongest within and adjacent to coal beds, suggesting that virtually all of the gas in the basin originated from coal beds that make up approximately five percent of the stratigraphic column. The deepest wells were drilled to explore for oil, but were abandoned without being tested.

Published values (Marsden, 1965) are known for solubility of methane in ground water. The accepted CUBIC FEET PER BARREL values are as follows:

SOLUBILITY CF/BARREL	DEPTH METERS	DEPTH FEET
0.2425	0 0	0.0
9.9043	500	1640.5
15.8872	1000	3281.0
20.0709	1500	4921.5
23.0693	2000	6562.0
25.2742	2500	8202.5
27.5002	3000	9843.0

These values are increased at greater depths due to increased pressure, and in several areas by the presence of interbedded coals and organic rich shale beds. Higher temperatures at greater depths gradually reduce the solubility of methane in the ground water.

Denali has identified portions of the Susitna Basin as an area for likely production of at least 137 TCF of dissolved gas. That gigantic resource can be confirmed with the initial set of wells to be drilled in the portion of the Susitna Basin north and west of Willow. Each well producing 1,000 gallons of water per minute with a conservative gas/water ratio of 27 cubic feet per barrel of water will yield 926 thousand cubic feet (926 mcf) per day of gas at surface temperatures and pressures. All of the produced water would then be returned to the same aquifer system from which it was pumped.

If each well produces for 360 days each year, dissolved gas production per well will be 333,396 mcf per year, or approximately .33 BCF per year. An eventual set of 300 wells would produce 100 BCF per year, exceeding total 2022 production from all existing dry gas fields in Cook Inlet Basin.

Each well in the Susitna Basin would not need to be drilled any deeper than 8,000 feet to disclose the gas saturated aquifers located in at least 5,000 feet of porous sands and sandstones interbedded with 400 to 500 feet of methane rich coal beds. With four wells drilled per section in the 1340 sections contained within the Susitna Basin Exploration Licenses to be operated by Denali, gas can be provided to Anchorage and other remote villages and cities throughout Alaska for hundreds of years, as the dissolved gas will continue to be replenished and recharged in the aquifer systems from the coal beds..

Gary F. Player

AAPG Certified Petroleum Geologist 3097
Utah Professional Geologist No. 5280804-2250

Appendix C
ASRC CONSULTING AND ENVIRONMENTAL SERVICES
Presentation and Supporting Documents

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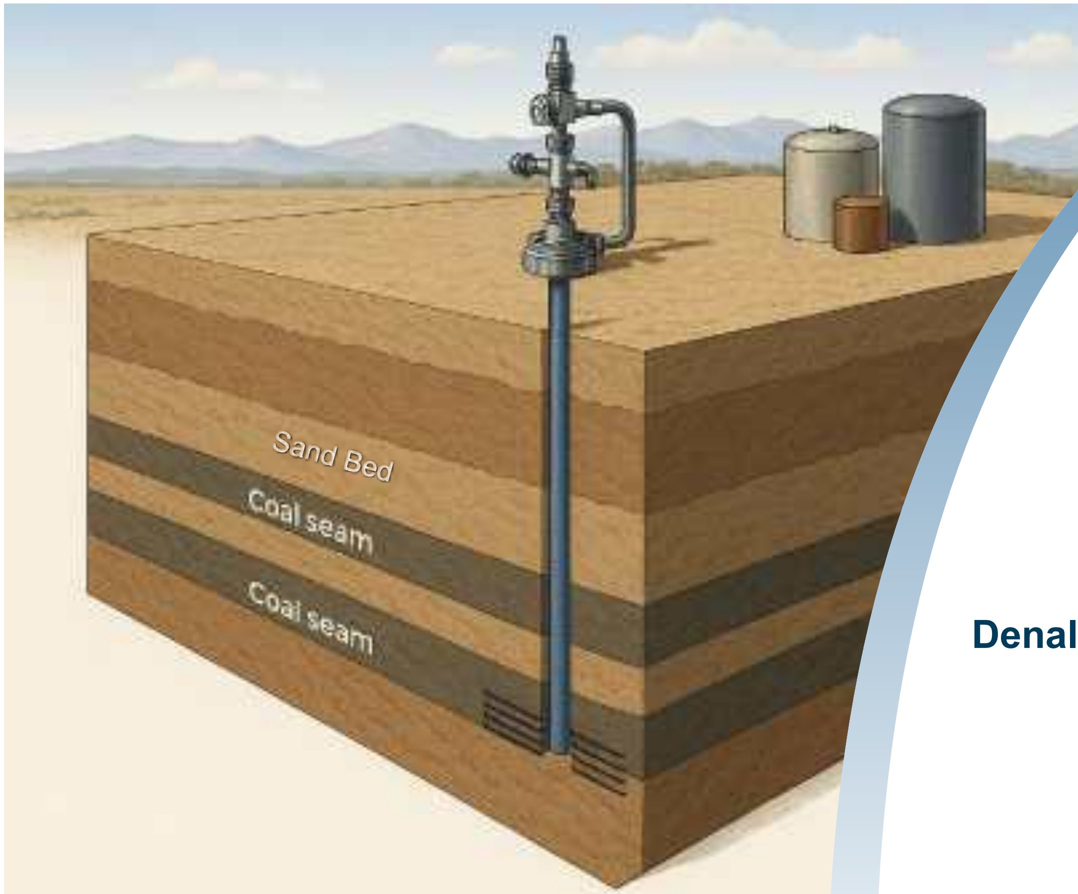


ASRC ENERGY

Susitna Valley Sand/Coal Bed Methane Development

Denali P&G – Alaska Natural Gas Corp.

Agenda

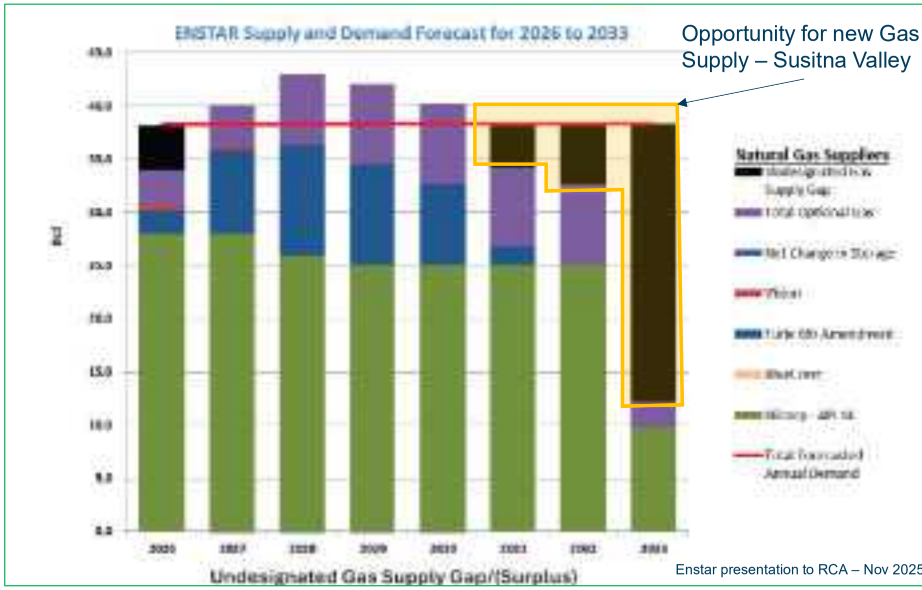
- **Executive Summary**
  - Cook Inlet Gas Supply
  - Estimates of Gas in Place
  - Summary of the Appraisal plan
- **Lease Area**
- **Subsurface Evaluation**
- **Development Plan - Appraisal**

ASRC ENERGY

Gas Supply in Cook Inlet

Gas Picture in Cook Inlet

- **Hilcorp is the dominant energy supplier for more than half the state's population, providing around 85% of the gas that heats and powers homes and businesses across much of Alaska.**
    - Current gas contracts face renewal in the next two to 9 years.
- **Hilcorp does not currently have enough natural gas reserves in Cook Inlet to provide for new gas contracts.**
- **Hilcorp has not committed to invest in future gas development in Cook Inlet.**
- **Denali Petroleum has had discussions with numerous utilities to negotiate long term contracts to supply 35 – 45 BCF/year**
    - Consequently, six of the largest utilities in Alaska have formed a new group to identify additional sources of natural gas to reduce their dependency on Hilcorp.



Enstar presentation to RCA – Nov 2025

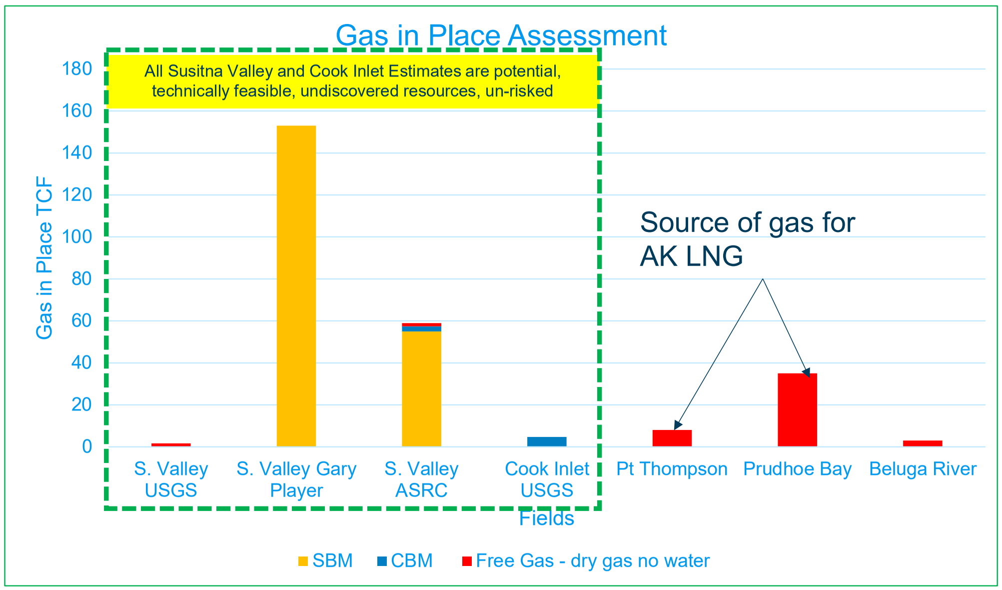
ASRC ENERGY

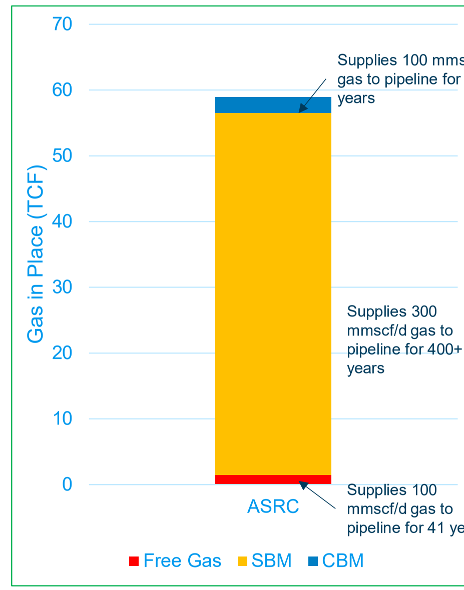
Estimates of Initial Gas Volumes

- **US Department of the Interior - US Geological Survey (USGS)**
  - Scientific Investigations Report 2012-1545: Coal Bed Methane
    - The Cook Inlet Gas Total Petroleum System (TPS), covers approximately 9,600,000 acres and comprises the Cook Inlet basin, Matanuska Valley, and Susitna lowland.
    - Coal beds serve as both source and reservoir for natural gas in Cook Inlet.
    - USGS Estimates 4.67 TCF of gas in Coal Bed Methane in Cook-Inlet and Susitna Basin

- **Gary F. Player, Professional Geologist and No. 5280804-2250**
  - Process for Estimating Dissolved Gas (SBM) Resources – May 30th, 2024
    - Production of natural gas dissolved in non-potable ground water in Japan, China, Italy and portions of OK and TX.
    - Production of sand bed methane (SBM) will require only the construction of relatively inexpensive wells near an existing gas pipeline.
    - Based on preliminary estimates, Gary Player estimates for dissolved gas in place is each section (640 acres) is 173 bcf (billion cubic feed). **For the entire Susitna Valley, this could be up to 250.3 TCF (trillion cubic feet).**
      - **With updated lease area by DNR Aug 2025, the revised estimate is 153.2 TCF**
- **USGS 2018-3170: Conventional Gas in Sandstone reservoirs**
  - Bulletin issued in 2017
    - Identified **1.7 TCF** of undiscovered, technically producible gas resource in **Susitna Valley TPS** (area of interest and subject of the Denali P&G Exploration Lease)
    - All the gas estimate expected to be found in **conventional accumulations in the Susitna Valley.**
- **Alaska Div. of Geological and Geophysical**
  - July 26, 2015, Report
    - Rock quality is equivalent in age to hydrocarbon bearing strata of prolific Cook Inlet basin.
    - Sandstone formation are good for hydrocarbon reservoirs, with interbedded mudstones acting as hydrocarbon seals
- **ASRC Assessment of gas in place**
  - Assessment area limited to deep and shallow basins
  - Benchmark with Lower 48 (San Juan Valley, Powder River Basin) for Coal Bed assessment
  - Review of seismic and other surveys (magnetic and gravity surveys)
  - Trail Ridge Unit 1 (1980) and Pure Kahlitna Unit 1 (1964) log analysis for free gas in sandstone reservoirs, coal bed (CBM) and dissolved gas (SBM).
    - **Estimated Initial Gas Place is 58.9 TCF**
    - **Includes coal beds (CBM), free gas in sandstone, and dissolved gas (SBM)**

Comparison of Susitna Valley to other gas fields in Alaska





ASRC ENERGY

Susitna Valley Lease Gas in Place Estimate by ASRC

- **Combined Lease Area = 567K acres - identified Deep (Blue) and Shallow (Yellow) and no-color basins for assessment.**
  - Free Gas in Conventional is estimated @ 1.5 TCF
  - Dissolved Gas (SBM) resource is estimated @ 55 TCF
  - Coal Bed Methane (CBM) Gas resource in place estimated @ 2.4 TCF
- **Total IGIP for Deep and Shallow basin = 58.9 TCF**

SBM

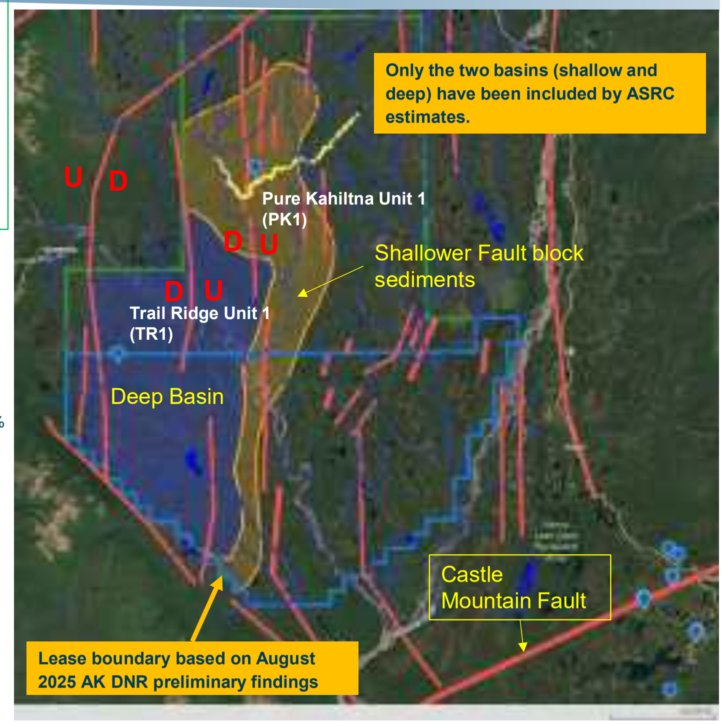
Basin	Area (K acre)	SBM TVT (ft)	GWR (scf/bbl)	GIP (bcf)
Shallow (Yellow)	102	3000	15	18,564
Deep (Blue)	139	5000	21	26,042
Non-Color	327	1500	12	10,374

Avg porosity = 23%

CBM

Basin	Area (K acre)	SBM TVT (ft)	Yield (scf/ton)	GIP (bcf)
Shallow (Yellow)	102	10	250	471
Deep (Blue)	139	20	350	1,890
Non-Color	327	0	150	0

ASRC ENERGY



Development Risk and Uncertainties

Risks

- **Drilling and Completion costs**
- **Permitting and environmental compliance**
- **Infrastructure and access to land**
- **Water handling and lifting/disposal**
- **Flow assurance (solids)**
- **Drilling complication and high Non-Productive time**

Uncertainties

- **Presence of dissolved gas in aquifer and its commercial viability**
  - Productivity and commerciality
- **Presence of coal bed and thickness, desorption, and dewatering behavior**
  - Extend of coal beds regionally
- **Presence of free gas and structural trap**
  - Extend of gas zones and structural traps.
  - Seals, structure closure, etc.

ASRC ENERGY

Executive Summary - ASRC Proposal for Appraisal of SBM and CBM

Total Cost of Appraisal Phase - $155M

Planning/Permitting/Procurement Phase

- **Subsurface and wells studies and finalize well locations**
  - Test two wells for SBM, CBM and free gas zones
  - 3rd well is to explore the graben block for deep gas (thermogenic)
- **Secure permits and land access (ADEC, AOGCC, ADNR, etc.)**
- **Procure Rig, Mobile Production and Water Filtration system**

Construction Phase

- **Build roads and pads/pits (Grant Lake) – Summer of 2026**
  - 2 pads with water disposal pits
  - One road to south to south of oil road (56 miles)
- **Well Construction Drilling and Completion in Winter of 2026-2027**
  - 2 wells in the south pad
  - 1 well in north pad

Testing Phase

- **Test two wells in Spring-Fall of 2027**
  - Well 1 CBM/SBM
  - Well 3 CBM or SBM

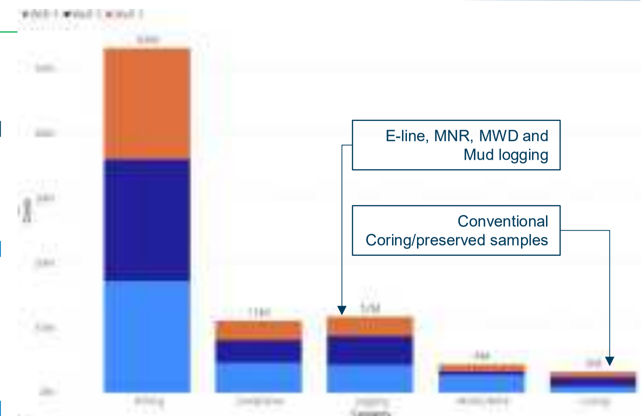
Post Testing Phase

- **Appraisal well analysis and assessment of next phase of development – 2028**
  - Lab analysis for CH4 in CBM
  - Future rig strategy

ASRC ENERGY

Appraisal Program Cost (3-well program) - $155M

• Road/Pad/Pit Construction Cost – Grant Lake	$45M
• Engineering and Permits (Well plans, permits, facility design)	$4M
• Rig MOB/DMOB	$4.5M
• ASRC well supervisory and coordinator	$3M
• Well Cost (Drilling and Completion 3 wells)	$80M
• Testing 2 wells – 1 unit from OSY, including transportation	$0.2M
• Additional Rig and Non-Rig well work – pull tubing, pump, etc.	$5M
• Water filtration and disposal – Rent or Buy RO and filtration system	$4M
• Operators/transportation (7 months) 3 x24 @$105/hr	$2M
• Hotels, Camps and services	$2.5M
• Road and pad maintenance	$1M
• Project Management Cost	$1M
• Post appraisal, Select/Define phase activities (labs, studies, rig strategy, development options, permits, SS and wells development design)	$3M



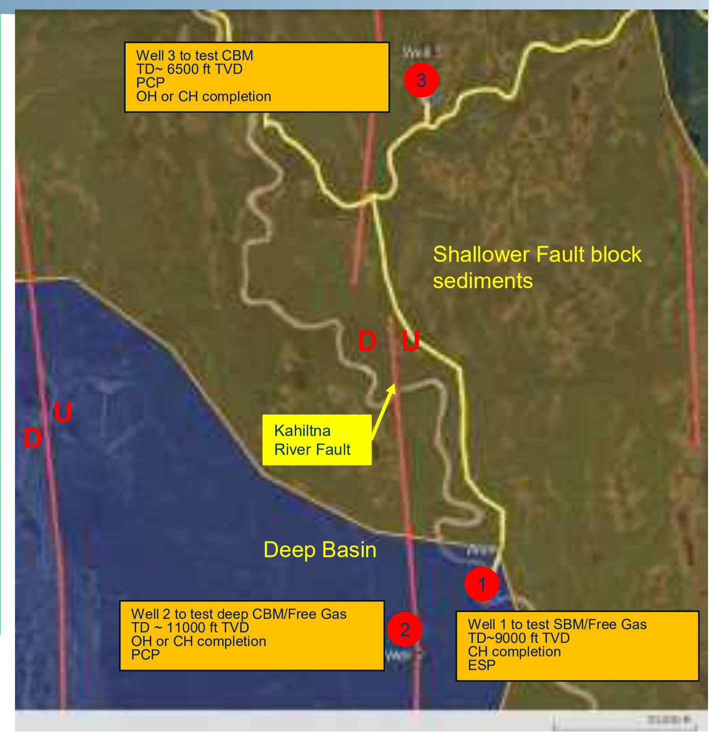
~$15M in coring and formation evaluation (E-Line, MWD, LWD), as well as Geological support during drilling phase.

P&A cost is not included, could be up to $15M if another rig mob/demob is required for P&A of 3 wells.

ASRC ENERGY

Appraisal Plan Objective: Assess gas in place volumes and Long-term production test of SBM/CBM

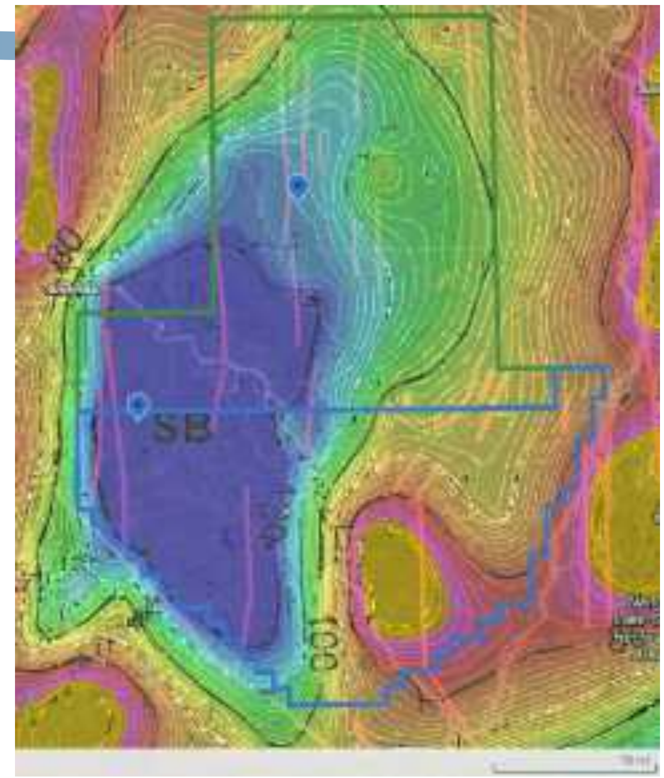
- **Up to 3 wells**
  1. Move to Appraisal Well 1 test SBM/deep CBM and trapped gas – highest priority
  2. Move to Appraisal Well 3 to assess CBM and SBM zones
  3. Move to Appraisal Well 2 to assess for deep CBM/Free Gas across down thrown fault block – high drilling risk across fault in high angle.
- **Test shallow and deep CBM/SBM**
  - Long Term test in 2 wells with Production Test Unit
  - Coring & logging in all wells in zones with coal beds and sand
  - Lab test for coal bed gas yield.



ASRC ENERGY

Executive Summary - Activities to date in support of appraisal plan

- Digitized and formation evaluation of Trail Ridge logs
- Studied and performed benchmark comparison with other CBM developments in Lower 48 (San Juan Valley, Powder River basin).
- Investigated seismic and gravity/magnetic surveys by AK and USGS archived data
- Integrated geophysical, magnetic and gravity data in Google Earth platform – thanks to Betsy Young/Corax
- Performed preliminary analysis of water disposal options for the appraisal wells based on ADEC rules and regulations.
- Received quotes for mobile test and water disposal units (OSY, LRS, Culligan, Pure Aqua, etc.)
- Identified potential well locations and appraisal strategy
- Scoped and provided cost estimated for the Appraisal Plan.



ASRC ENERGY

1

Lease Area Description

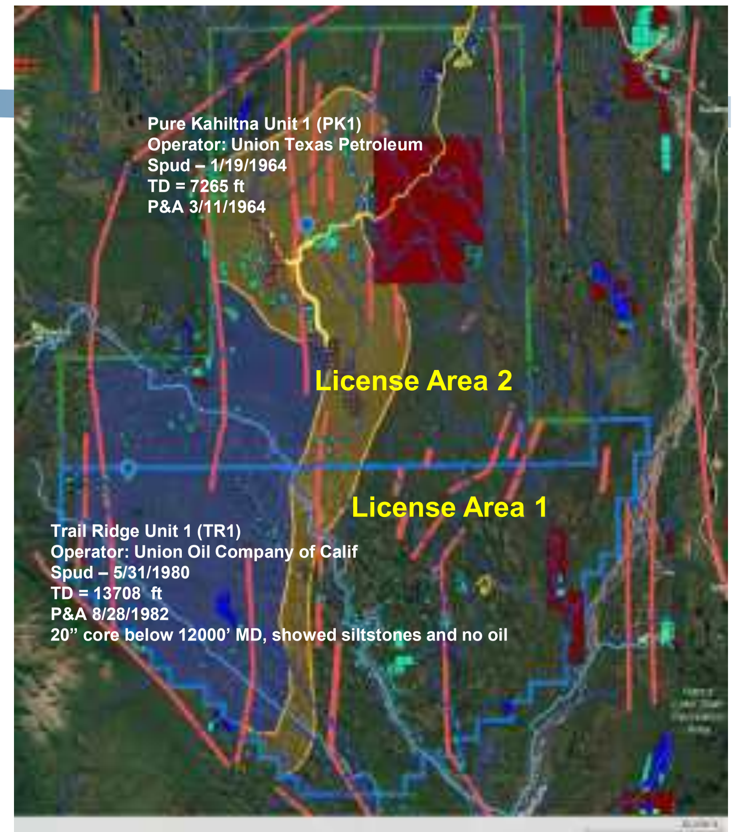
Susitna Valley

ASRC ENERGY

License Area

- **License Area 1**
  - 264 K acres
  - Elevation ranges from 48 to 418 ft, with median of 147 ft.
- **License Area 2**
  - 303 K acres
  - Elevation ranges from 93 to 1094 ft, with median of 365 ft.
- **2 exploration wells (1964 and 1980)**
  - Good gas shows in sands and coal beds
  - Encountered coal beds in deeper sections (some over 50' thick)

ASRC ENERGY



2

Subsurface Eval

Susitna Valley CBM

ASRC ENERGY

Geological Description of Susitna Valley

- **Susitna Basin separated from Cook Inlet Basin by Castle Mountain Fault.**
- **Deep basin (up to 15,000’) sourced exclusively from Alaska Range, Talkeetna Mountains and Tordillo Mountains.**
- **Trail Ridge well shows approximately 9000’ of equivalent Kenai Group (Sterling, Beluga, Tyonek) non-marine sedimentary section derived from fluvial and lacustrine processes, consisting of sandstones, conglomerates and siltstones/claystones.**
  - Sandstones are of high quality (up to 2 darcy’s) and only moderately consolidated.
  - Lower units (down to 12,000’) show increase in volcanics and coals.
  - Coal sequences in Unit E show good possibility for CBM.
- **Pure Kahiltna well shows very different stratigraphy, likely due to residing in different fault block and timing of faulting and associated sediment accommodation versus Trail Ridge well.**
  - Only 500’ of equivalent Kenai Group sediment
  - Consists largely of 6700’ of fluvial derived clean sandstones, coal beds, conglomerates and volcanics. Time equivalent to deeper Cook Inlet units (Hemlock and West Foreland formations).

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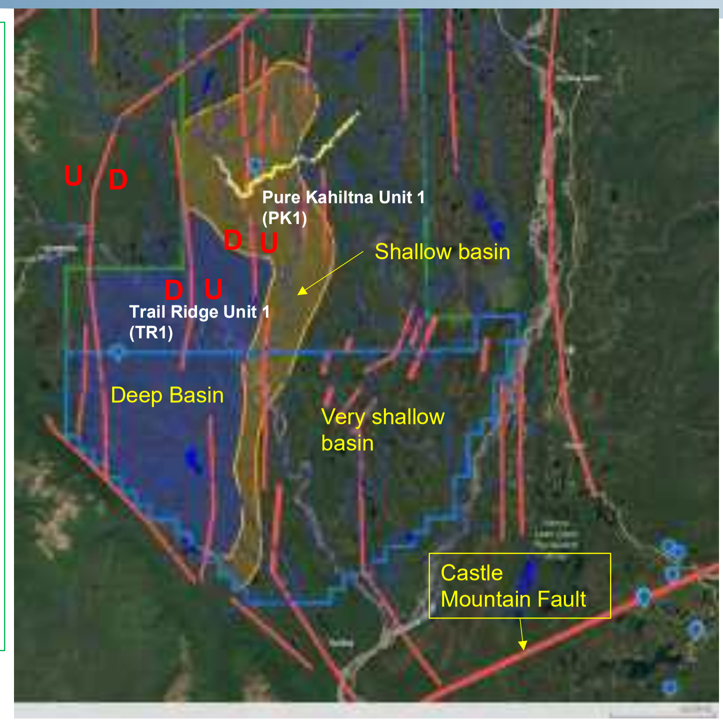
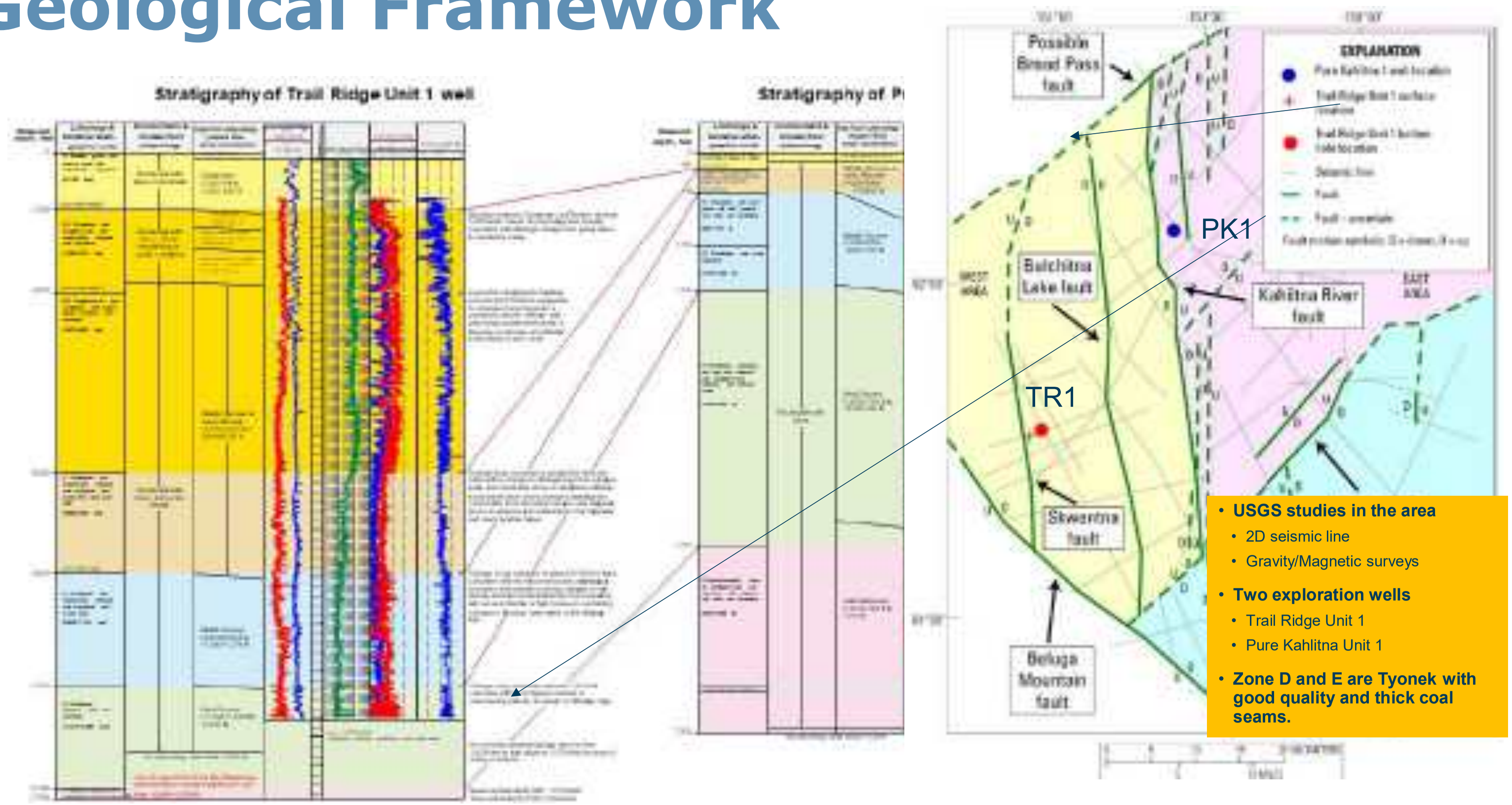
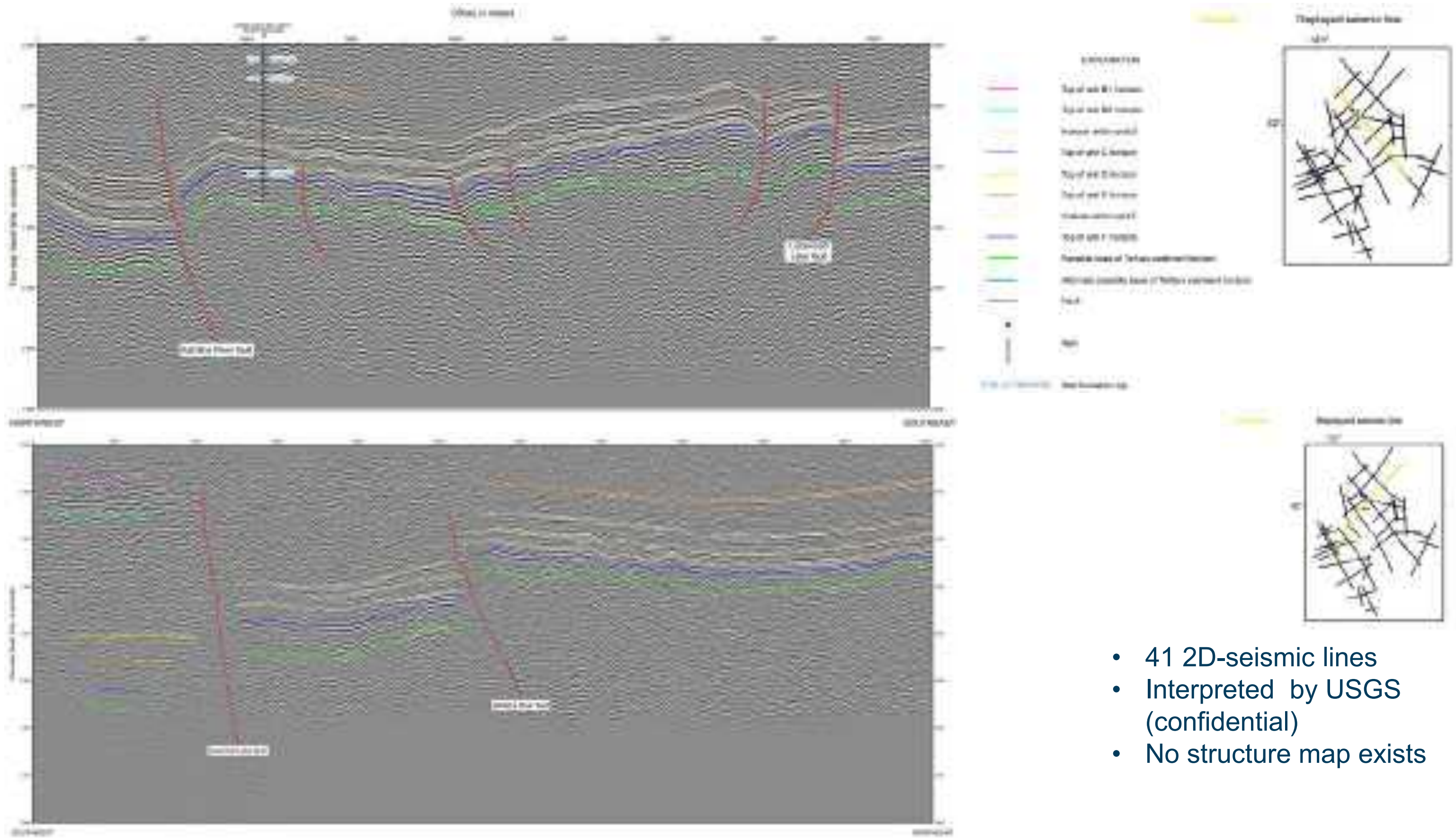


Geological Framework

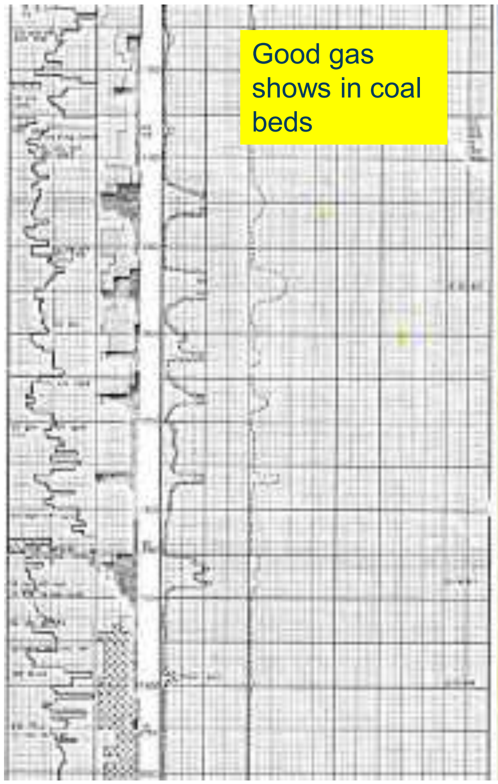


- **USGS studies in the area**
  - 2D seismic line
  - Gravity/Magnetic surveys
- **Two exploration wells**
  - Trail Ridge Unit 1
  - Pure Kahlitna Unit 1
- **Zone D and E are Tyonek with good quality and thick coal seams.**

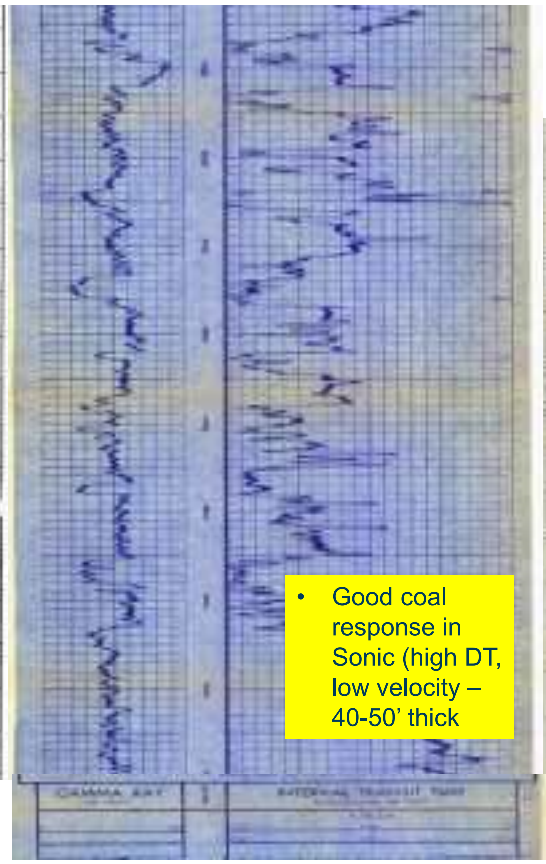


- 41 2D-seismic lines
- Interpreted by USGS (confidential)
- No structure map exists

Pure Kahlitna Unit 1



Good gas shows in coal beds

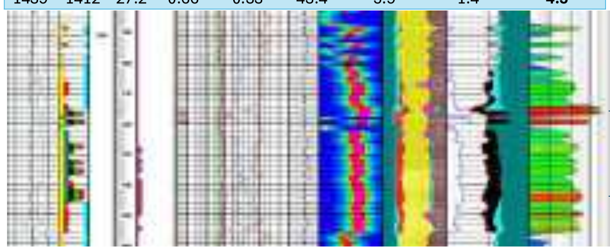


- Good coal response in Sonic (high DT, low velocity – 40-50' thick

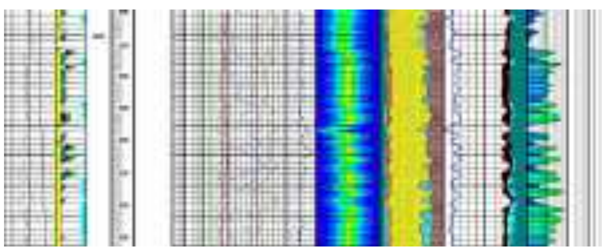
- Coal beds visible and detectable on conductivity logs.

Trail Ridge Unit 1 Log Analysis – Trapped gas and SBM Plays

Base TVD (ft)	Top TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
1439	1412	27.2	0.66	0.33	43.4	5.9	1.4	**4.5**



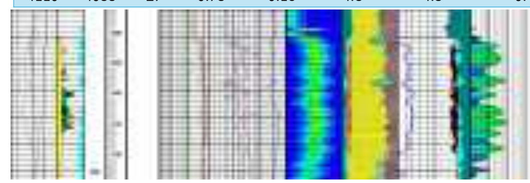
27' thick gas zone with no mobile water, 43 md, 33% porosity
Trapped Gas
Recoverable gas/640 acre = 4 bcf



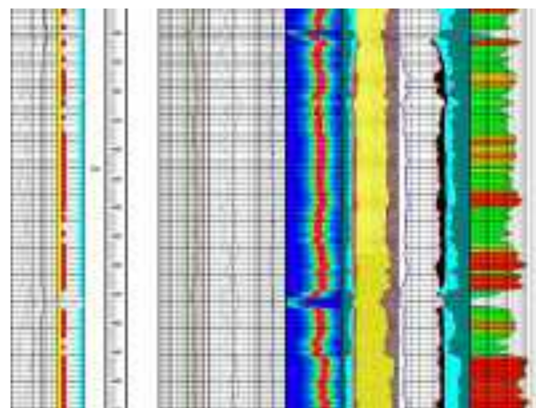
30' thick gas zone with some mobile water, 10 md, 18% porosity
SBM
Recoverable gas/640 acre = 0.5 bcf

Base TVD (ft)	Top TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
2003	1972	30.4	0.68	0.18	1.6	3.8	1.3	**2.5**

Base TVD (ft)	Top TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
4110	4083	27	0.73	0.16	4.3	4.3	0.4	**3.9**



27' thick gas zone with some mobile water, 4.3 md, 16% porosity
SBM
Recoverable gas/640 acre = 0.8 bcf

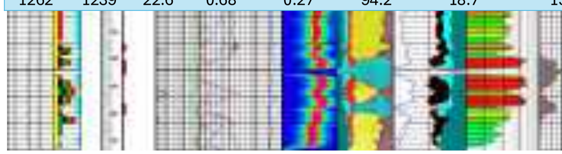


179' thick gas zone with high mobile water, 32 md, 26% porosity, unconciliated sand
SBM
Recoverable gas/640 acre = 3 bcf

Base of TVD (ft)	Top of TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
6525	6346	179.2	0.84	0.26	31.9	59.9	0.2	**59.7**

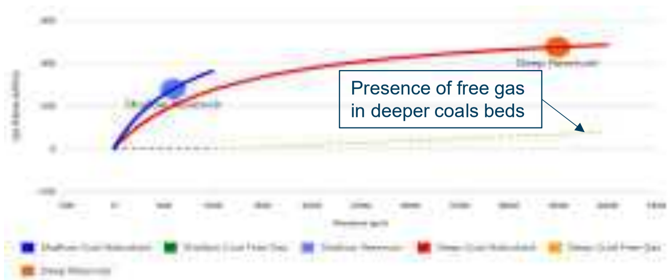
Trail Ridge Unit 1 Log Analysis – CBM Plays

Base of TVD (ft)	Top of TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
1262	1239	22.6	0.68	0.27	94.2	18.7	15.3	**3.4**

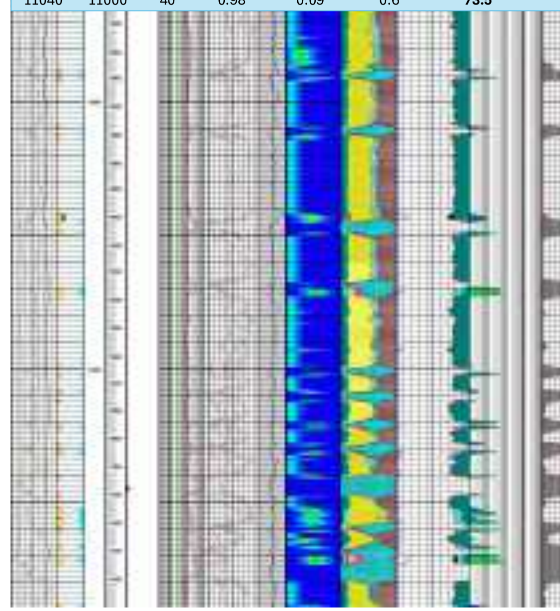


23' thick gas zone with some mobile water, 94 md, 27% porosity
Trapped Gas
Recoverable gas/640 acre = 3 bcf

Longmuir curves for absorbed and free gas in Coal beds



Base of TVD (ft)	Top of TVD (ft)	TVT (ft)	Avg SW (frac)	Average of PHIE (frac)	Average of PERM (md)	Total Gas (bcf/640 ac)	Gas absorbed (bcf/640 ac)	Free gas (bcf/640 acre)
11040	11000	40	0.98	0.09	0.6	**73.5**	**71.6**	**1.9**



40' thick coal seam bearing zone with high absorbed gas excess of 400 scf/ton
CBM
Recoverable gas/640 acre ~ 1.5 bcf

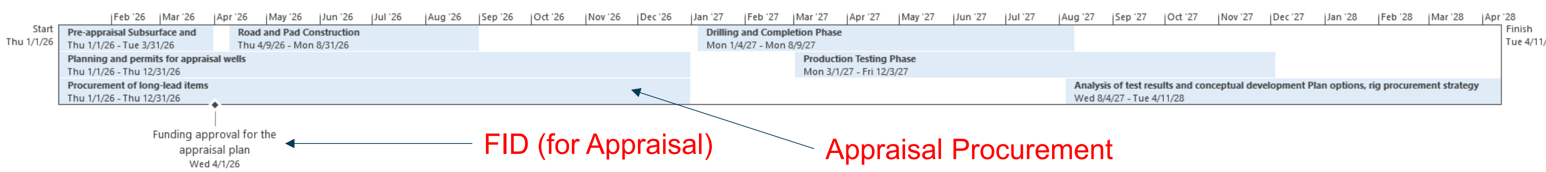
3

Development Plan

Susitna Valley Appraisal Program

ASRC ENERGY

Development Plan Summary



Appraise → TG → **Select/Define** → TG → **Execute**

- **Appraisal – Jan 2026 to 1Q 2028**
  - Finalize plan for up to 3 wells to explore and appraise
    - Targets are SBM,CBM and free gas zones
    - Formation Evaluation and LT production testing
  - Develop options SBM and CBM development concepts
  - Determine if additional appraisal is needed

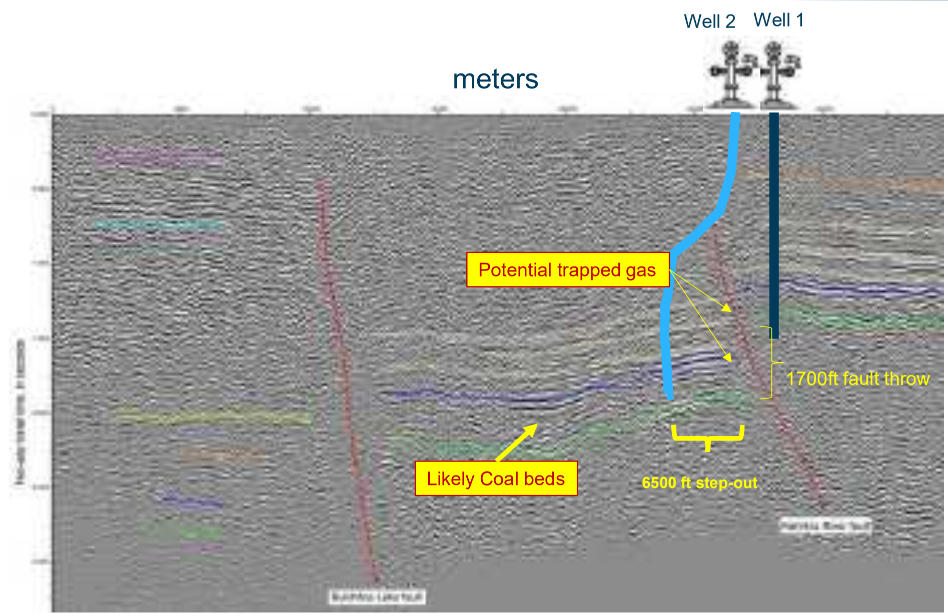
- **Select and Define stage – April 2028 - 2030**
  - Secure Permits and Land
  - FEED and EPC
  - Develop a contracting strategy for rigs, facilities, roads, infrastructure, etc.
  - Finalize the Development Plan for Susitna Valley CBM/SBM/Free Gas development
  - Proceed to FID and start EPC

- **Execute and Operate- 2030**
  - Procurement and construction phase and drilling activity
    - Road/Pad and disposal wells
    - CBM/SBM/Gas wells
    - Pipeline by ENSTAR
  - First gas online in 2031?

TG: Tollgate – approval to move from one stage to next stage of Project

Well 1 and 2 Seismic and Structure play

- Down thrown block juxtaposed against low perm rock in the up thrown block
- Trail Ridge Unit 1 shows similar trap mechanism in shallower sands
- Good opportunity to assess free gas in place with structural traps



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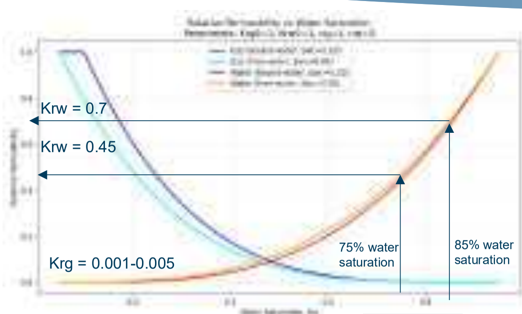
Importance of finding dryer gas

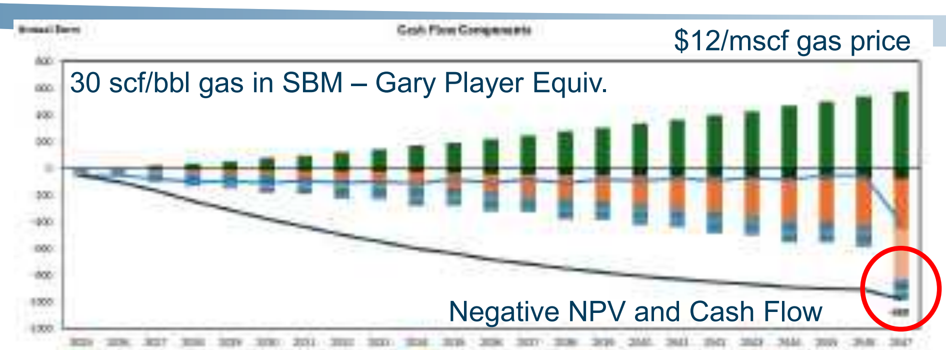


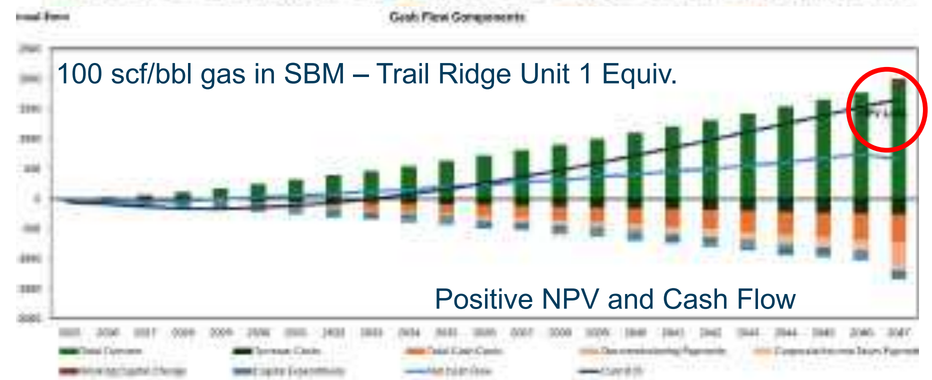
Free gas development results in 100 bwpd for 1 mmscf/d of gas
Water disposal cost at $0.10/bbl = $10/day/well

SBM gas development results in 10000 bwpd for 1 mmscf/d of gas
Water disposal cost at $0.10/bbl = $1000/day/well

Fraction of gas to water (v/v) = 0.07
Translates to GWR ~ 100 scf/bbl in Trial Ridge Unit 1

$12/mscf gas price





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Grand Lake Road Proposal – Roads/Pad and Pits

- **Gant Lake has mining claims in the area**
  - Holds permit to build roads to gold mine claims in the appraisal area
- **Grant Lake very familiar with Susitna Valley**
- **For the project, we propose contracting road, pits and pad construction to Grant Lake.**

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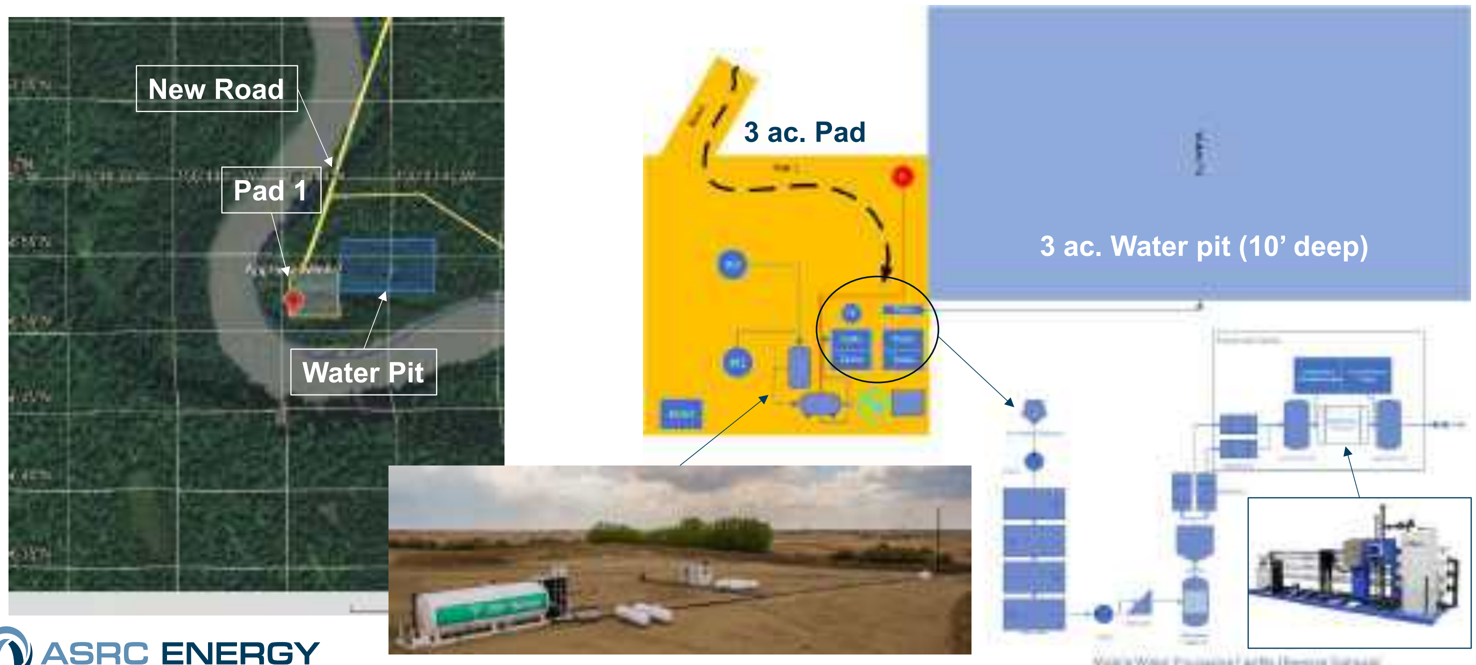
Pad 1 (Wells 1 and 2)



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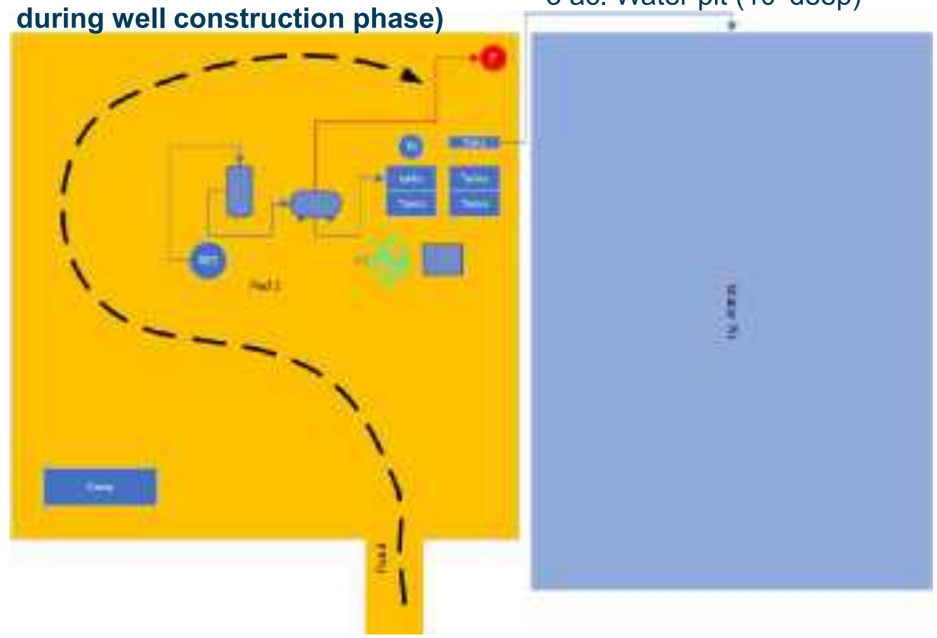
Pad 2 (Wells 3)



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Denali P&G Susitna Valley Project

Investment pack - $50K

- Discuss and Agree on Appraisal Plan with Grant Lake, Denali P&G, and AES
- Agree on final delivery for this stage of the project (document/slide pack)
- **Deliver an investor pack which addresses the bankable appraisal plan**

Appraisal planning (1H 2026 - $250K)

- **Finalize the appraisal wells' BH and surface locations ($140K)**
  - Digitize 2D seismic lines and interpret PK1 log – $26 K
  - Develop a structural map of the Susitna Valley using seismic and well data
  - Develop a completion strategy and coring program for appraisal well
- **Procurement process for appraisal well (drilling, testing, logging, coring, lab studies, etc) - $50K**
- **Start permitting and environmental studies needed for drilling and testing ($10K)**
  - Explore options on produced water disposal with AKDEC
  - Needs significant land activity (private property, right of way, easements, etc.)
- **Finalize the cost of appraisal program, including permits, roads, infrastructure and testing – March 2026**
- **Drilling Cost reduction and Rig procurement strategy for the long-term development plan ($50K)**

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Outcome – Successful Appraisal – Low Well Cost

CBM only

35 bcf/yr for 30 years – 1.2 Tcf Proved Dev.
1600 wells
Capex = $8,000 M
Opex = $6,700M
IRR = 54%
NPV = $1,022 M

- No presence of free gas zones
- No commercially viable Dissolved gas (SBM) zones
- Commercially viable CBM zones (minimum of 40 ft thickness)

SBM only

35 bcf/yr for 30 years – 1.2 Tcf Proved Dev.
330 wells
Capex = $1,232 M
Opex = $8,030 M
IRR = 27%
NPV = $1,430M

- No presence of free gas zones
- Commercially viable Dissolved gas (SBM) zones (minimum 1500 ft)
- No Commercially viable CBM zones

Free Gas only

35 bcf/yr for 30 years – 1.2 Tcf Proved Dev.
237 wells
Capex = $1,452 M
Opex = $2,180 M
IRR = 88%
NPV = $2,771 M

- Commercially viable gas zone (minimum 15 ft)
- No commercially viable Dissolved gas (SBM) zones
- No Commercially viable CBM zones

Key Assumptions - $2M per well, $0.5M per Rig WO, $0.05/bbl operating cost for water handling, $0.8/mscf gas operating cost

ASRC ENERGY

Outcome – Successful Appraisal – Normal Well Cost

35 bcf/yr for 30 years – 1.2 Tcf Proved Dev.
1600 wells: 35 Year Drilling Campaign
Capex = $17,600 M
Opex = $6,700M
IRR = -
NPV = $-730 M

CBM only

- No presence of free gas zones
- No commercially viable Dissolved gas (SBM) zones
- Commercially viable CBM zones (minimum of 40 ft thickness)

35 bcf/yr for 30 years – 1.2 Tcf Proved Dev.
330 wells – 5 Year Drilling Campaign
Capex = $2,650 M
Opex = $8,030 M
IRR = 13%
NPV = $713M

SBM only

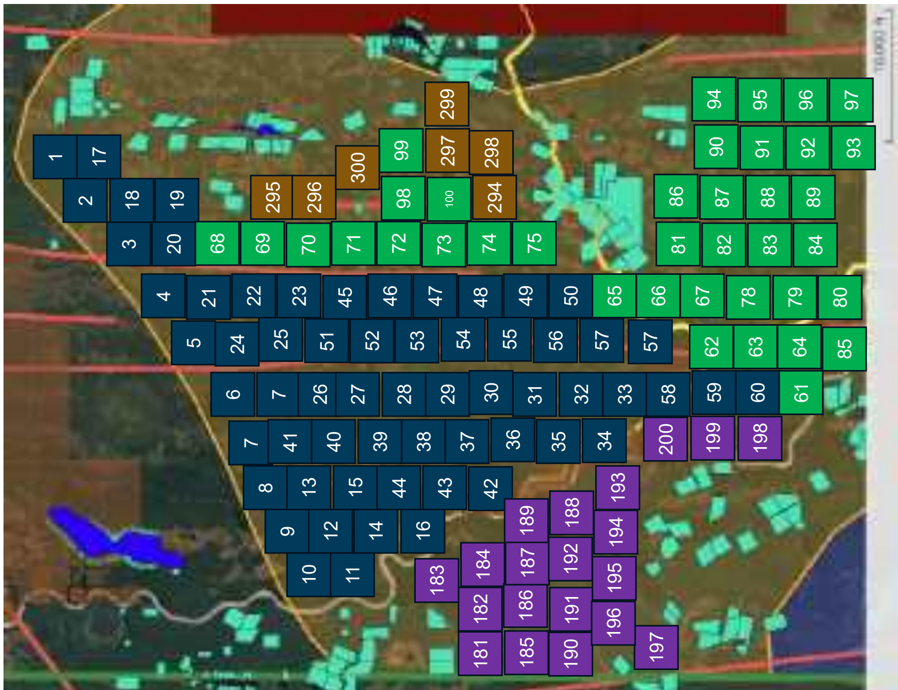
- No presence of free gas zones
- Commercially viable Dissolved gas (SBM) zones (minimum 1500 ft)
- No Commercially viable CBM zones

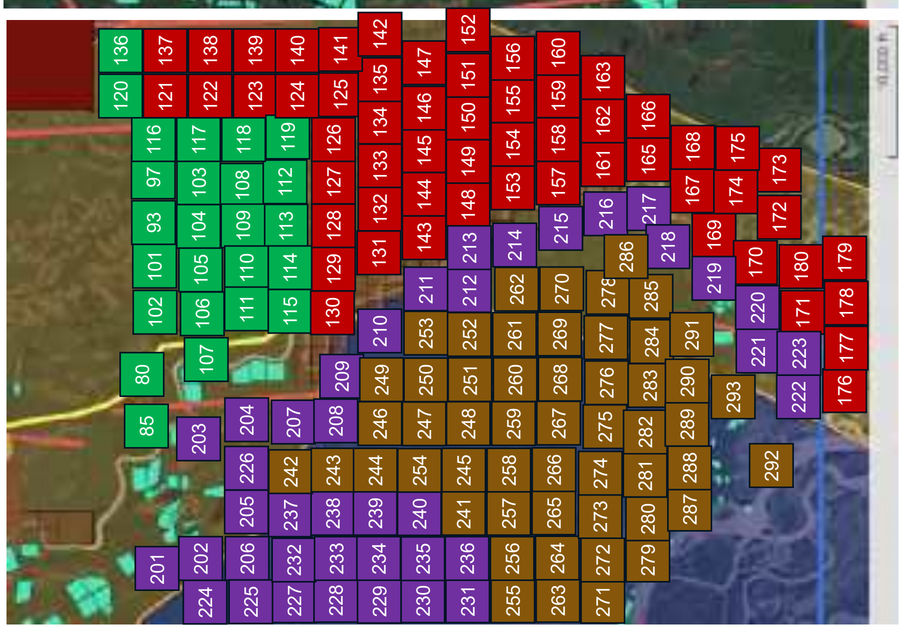
35 bcf/yr for 30 years – 1.2 Tcf Proved Dev.
237 wells: 35 Year Drilling Campaign
Capex = $2,840 M
Opex = $2,180 M
IRR = 84%
NPV = $2,520 M

Free Gas only

- Commercially viable gas zone (minimum 15 ft)
- No commercially viable Dissolved gas (SBM) zones
- No Commercially viable CBM zones

Key Assumptions - $6M per well, $0.5M per Rig WOs, $0.05/bbl operating cost for water handling, $0.8/mscf gas operating cost



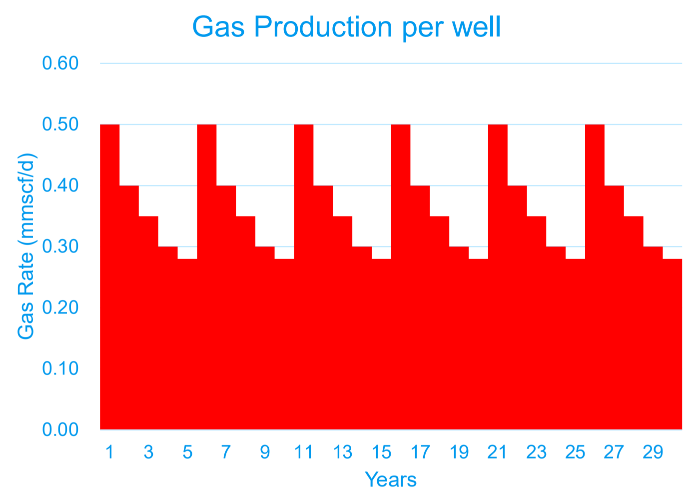


SBM Development

Assumptions

- Max of 12 wells per pad (up to 2 disposal well per pad)
- One workover every 5 years to replace pump and complete in a shallow sand interval @ $0.5M/Well
- 160-acre per well development
- 12 drill sites and processing centers
- No pipeline cost – ENSTAR will pay, in place by 2030

Gas Rate/well (30 years)



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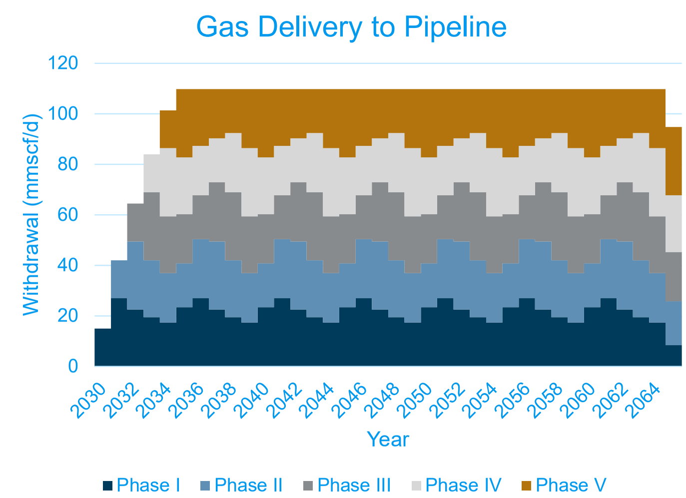
SBM Development Potential

Development Concept

- Five phases (5-year drilling program)
- 5-yr/well WO and recompletion program.
- Re-injection into aquifer
- $13M Pad construction cost
- Production start in 2030 – reaches 100+ mmscf/d by 2035
- 30-year delivery at 100+ mmscf/d – over 1.2 TCP (35 bcf/yr)
- $0.05 per bbl water disposal cost
- $0.8 per mscf gas lifting and processing cost

Full Field Development Gas Rate



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Appendix D
Water Filtration Unit
Preliminary Design and Cost Estimate

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TECHNICAL MEMORANDUM

To: Doshier, Ron; Shirzadi, Shawn

From: Shirzadi, Rysen

CC: Twogood, Christina; Zsolt, Liam; Curley, Pat

Date: 11/19/2025

Subject: Coalbed Methane (CBM) Produced Water Disposal Options

Project No.: 18322-01

Introduction

The disposal of water produced from coalbed methane (CBM) extraction is subject to federal and state regulations, primarily focused on protecting surface water, groundwater, and soil resources.

- **Discharge to Land/Subsurface:** Allowed under Alaska Department of Environmental Conservation (ADEC) land application regulations, contingent on meeting soil and groundwater protection standards. APDES and UIC Class II surface water and injection standards do not apply.

Water Quality Standards and Limitations

While drinking water standards may not apply, each option is governed by distinct water quality criteria and limitations to ensure environmental protection. Please refer to Table 1 Which summarizes the component-specific standards for each disposal method.

Table 1. ADEC Component-Specific Standards

Component	ADEC
Total Dissolved Solids (TDS)	No numeric limit statewide; site-specific. TDS >500–1,000 mg/L often triggers review for long-term salt/heavy metal accumulation. Must not alter natural conditions or harm aquatic life.
Sediment/Turbidity	It must not cause ponding, runoff, or sedimentation. BMPs required.
Dissolved Oxygen (DO)	Not applicable unless water reaches surface.
Dissolved Inorganic Substances (Brine)	Must not exceed background groundwater limits. Often TDS and chloride-based limits apply. Sodium Adsorption Ratio (SAR) may be assessed for soil impacts.
Petroleum Hydrocarbons	No visible sheen. Hydrocarbon content must not impact vegetation, soil infiltration, or groundwater.
Temperature	Temperature control is not regulated unless discharge reaches surface water or impacts groundwater temperature.
pH	Generally, the same: 6.5–8.5 SU to prevent groundwater impacts.
Other Toxic/Hazardous Substances	Must not exceed groundwater protection levels (e.g., ADEC Table C cleanup levels).

Source Water Sampling

On November 18th 2025, source water from the well was delivered to 2401 Cinnabar Loop for Testing. All testing was performed on November 18th and the results are below, Images from the testing can be found in **Appendix A**.

Property	Method	Test 1	Test 2
Settleable Solids (mL/L)	Imhoff Cone	6.00	6.50
TDS (mg/L)	YSI Pro Quattro	20,091.50	20,169.50
TDS (mg/L)	Hanna Pro	**OL**	**OL**
Turbidity (NTU)	Oakton Turbidimeter	333.00	369.00
Turbidity Post Settling (NTU)	Oakton Turbidimeter	84.70	87.40
DO (mg/L)	YSI Pro Quattro	9.10	10.07
pH	Hanna Pro	7.01	7.01
pH	pH Strips	6.80	6.20
pH	YSI Pro Quattro	6.93	7.02
Conductivity (µS/cm)	YSI Pro Quattro	25,191.00	25,304.00
Temp (°C)	YSI Pro Quattro	15.30	15.30

Recommended Treatment Options

Design Basis

Flowrate: Approximately 5,000 bbl/day (210,000 gpd, ~145 gpm average).

Treatment design flow: 200–220 gpm to provide hydraulic and operational margin.

Influent water quality:

- TDS ≈ 20,091 mg/L
- Turbidity (disturbed) ≈ 333 NTU
- Turbidity (settled) ≈ 84.7 NTU
- Settleable solids ≈ 6.5 mL/L
- pH ≈ 7.0

Discharge method: Land infiltration under ADEC 18 AAC 72.

Regulatory drivers:

- No ponding, runoff, or surface erosion.
- No visible sheen or hydrocarbon impacts on soil or vegetation.
- TDS and dissolved inorganics must not exceed groundwater background or cause long-term salinity accumulation.
- pH between 6.5 and 8.5 SU.

- Groundwater at the compliance boundary must not exceed Table C cleanup levels.

Primary technical challenge: Influent TDS (~20,000 mg/L) is significantly above typical groundwater background values and therefore requires desalination to protect groundwater.

The AES Remediation team never needed to control TDS in concentrated brines, so the existing equipment would need to be modified to include a TDS removal step and ensure that the water entering the TDS removal technology meets the needs of that technology.

Process Description

The proposed treatment system includes a solids removal train, hydrocarbon removal, advanced TDS reduction via reverse osmosis (RO), and land infiltration of the polished permeate. Concentrate (RO brine) is collected and disposed of through a separate regulated pathway and does not enter the land-application system.

Raw Water Transfer and Equalization

Produced water is pumped to an equalization tank providing 2–4 hours of residence time. The EQ tank buffers hydraulic surges, allows sand and grit to settle, and provides consistent feed to downstream treatment processes.

Coarse Solids Screening

A bar screen or inline basket strainer (3–6 mm) removes large debris, preventing downstream fouling and protecting equipment.

Coagulation and Flocculation

Coagulant is injected in a rapid-mix tank, followed by 15–30 minutes of flocculation. This step destabilizes fine colloidal clay and silt, forming larger floc particles suitable for removal in clarification.

Primary Clarification

An inclined-plate clarifier provides separation of flocculated solids from the water column. Sludge is collected in a cone bottom and periodically transferred to sludge handling equipment for dewatering and proper disposal.

Multimedia Filtration

The clarified water passes through dual multimedia filters (sand/anthracite configuration). Filters remove remaining turbidity to protect downstream membrane systems and ensure compliance with ADEC’s no-sedimentation/ponding requirement at the land-application area.

Bag / Cartridge Filtration

A duplex bag or cartridge filter skid (10 µm followed by 1–5 µm) provides fine polishing and serves as critical pretreatment for the RO system.

*Oil and Grease Removal**

A coalescing-plate oil–water separator removes free and dispersed hydrocarbons. Oil is skimmed to a waste-oil container. This ensures that discharged water does not create visible sheen or affect soil/vegetation infiltration properties.

Granular Activated Carbon (GAC) Pre-Polish

Lead/lag GAC vessels remove trace hydrocarbons and organics and protect RO membranes from fouling. This provides an additional barrier to meeting groundwater cleanup levels.

Reverse Osmosis – Pure Aqua Industrial BWRO RO-500

The *Pure Aqua BWRO RO-500 industrial brackish water RO system* serves as the core TDS-reduction process.

- Configured for high-TDS feed (~20,000 mg/L).
- Produces low-TDS permeate meeting groundwater protection targets.
- Recovery expected at 75–85%, subject to vendor design.
- Permeate sent to land infiltration.
- Concentrate (high-TDS brine) isolated in a dedicated tank and transported or injected under an appropriate, separate disposal permit.

RO Support Systems

Antiscalant dosing, cartridge prefilters, and a clean-in-place (CIP) system are included to maintain membrane performance and reliability.

*pH Adjustment**

Inline pH monitoring and chemical injection maintain final discharge pH between 6.5 and 8.5 SU, consistent with groundwater protection expectations.

Final GAC Polish (Optional)

A single post-RO GAC vessel may be used for additional organic polishing to ensure robust compliance with groundwater protection criteria.

Effluent Monitoring and Control

Effluent is monitored for flow, turbidity, conductivity (TDS), and pH. Sampling ports allow for periodic laboratory analysis of TDS, SAR, hydrocarbons, and metals as required by ADEC.

*Unlikely to be required, possibly needed if source water properties change

ROM Cost Estimate

Component	ROM Equipment Cost (USD)	Notes
Raw Water Pump(s) + Equalization Tank (4x1000/m) + transportation	\$100,000 - \$250,000	Pumps + ~25,000-40,000 gal tank, mixer, instrumentation, Frac Tanks
Coarse Screen / Strainer (450/m) +transportation	\$10,000 - \$40,000	Inline bar screen / basket strainer for ~200 gpm
Coagulation/Flocculation Skid	\$75,000 - \$200,000	Rapid-mix tank + floc basin + mixers + chemical feed system
Inclined Plate Clarifier	\$150,000 - \$300,000	Inclined plate settler sized for 200-220 gpm
Sludge Handling (Tank & Dewatering) 1 x 1000/m + transportation	\$50,000 - \$150,000	Sludge tank + transfer pump + geobag or small filter press
Multimedia Sand Filters (2 vessels)	\$150,000 - \$250,000	Two or more vessels for ~200-220 gpm load
Bag/Cartridge Filter Polishing Skid	\$20,000 - \$75,000	Duplex filters 10 μm → 1-5 μm
*Coalescing Oil-Water Separator**	\$75,000 - \$200,000	Separator sized for ~200 gpm, skimmer system
GAC Pre-Polish (Lead/Lag)	\$75,000 - \$200,000	GAC vessels for ~200-220 gpm flow
RO System (Pure Aqua BWRO RO-500)	\$400,000 - \$1,000,000**	High-TDS configuration (~20,000 mg/L TDS feed) for ~200-220 gpm / ~200,000-300,000 gpd permeate
RO Chemical Feed & CIP System	\$50,000 - \$150,000	Antiscalant dosing, CIP tank/pump, instrumentation
RO Concentrate (Brine) Storage & Transfer	\$75,000 - \$200,000	Storage tank + pump for reject brine management + Trucking away Concentrate
*pH Adjustment Skid**	\$25,000 - \$75,000	Metering pumps, day tanks, pH probe, static mixer

Final GAC Polish (if used)	$50,000 - $150,000	Vessel for final polishing of organics post-RO
Effluent Monitoring & Control System (PLC/SCADA/Analyzers)	$10,000 - $50,000	Flow meter, turbidity, conductivity (TDS surrogate), pH, sample ports, data logging

*Unlikely to be required, possibly needed if source water properties change
**Quote requested on 11/17/2025, no response as of 11/19/2025

All in, to develop a skid like this would cost between $1.5 -3 MM, with the RO system making up the majority of the cost.

Conclusion

Given the measured water quality (TDS approximately 20,000 mg/L, high turbidity, and neutral pH), surface discharge under an ADEC permit will only be feasible with an advanced treatment train that combines solids removal, hydrocarbon control, and high recovery desalination. We recommend a treatment system built around a Pure Aqua Industrial Brackish Water Reverse Osmosis BWRO RO-500 series unit, preceded by clarification and filtration designed to consistently deliver low turbidity feed to the RO system.

The RO-500 trains are rated for 200,000 to 900,000 gallons per day of brackish feedwater and can be configured for higher TDS applications with appropriate pretreatment, antiscalant dosing, and membrane selection. The front end of the system (equalization, coagulation and flocculation, inclined plate clarification, multimedia filtration, bag filtration, and coalescing plate oil removal) is sized for approximately 200 to 220 gpm and will reduce settleable solids and turbidity from the observed 6.5 mL/L and 333 NTU into a range suitable for RO operation. The RO-500 module then provides the necessary TDS reduction to approach background conditions in the receiving water, with the permeate directed to final pH and DO conditioning and then to the permitted surface discharge, and the brine reject routed to a separate regulated disposal pathway such as Class II UIC or trucking.

This configuration aligns with ADEC expectations that surface discharges not alter natural conditions or harm aquatic life, while recognizing that high salinity brine is a separate waste stream that cannot be managed through the same discharge point.

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Appendix A – Pictures from Laboratory Testing

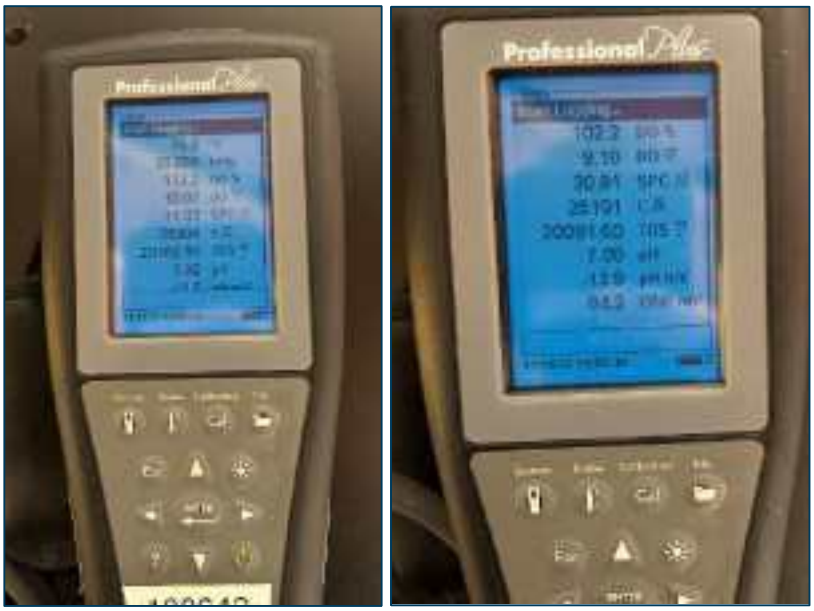

Exhibit a. – YSI Pro Quatro Results for Source Liquid

Exhibit b. – Turbidity Measurements 1 and 2, Pre and Post Settling

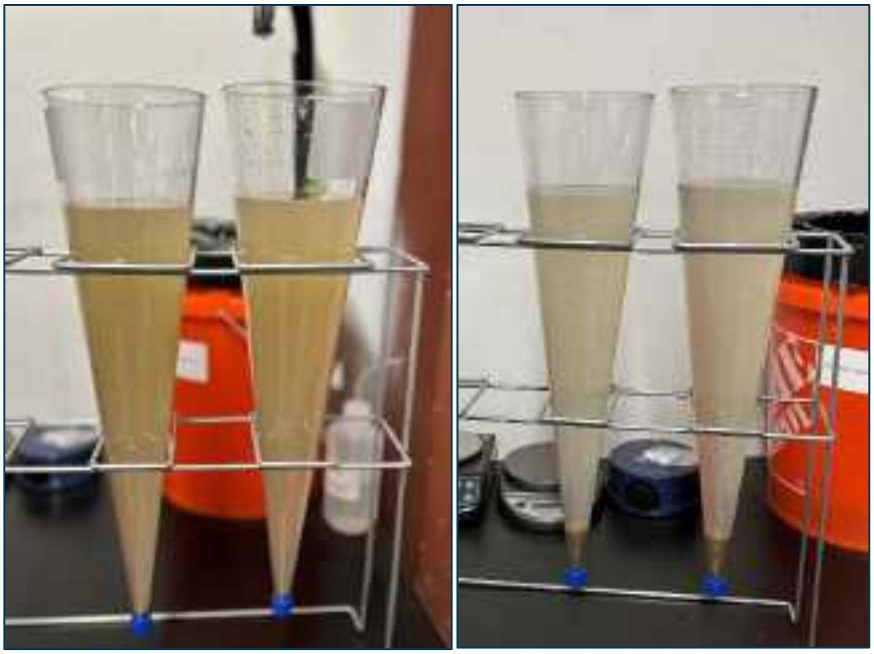

Exhibit c. – Pre and Post Settled Source Water in Imhoff Cones

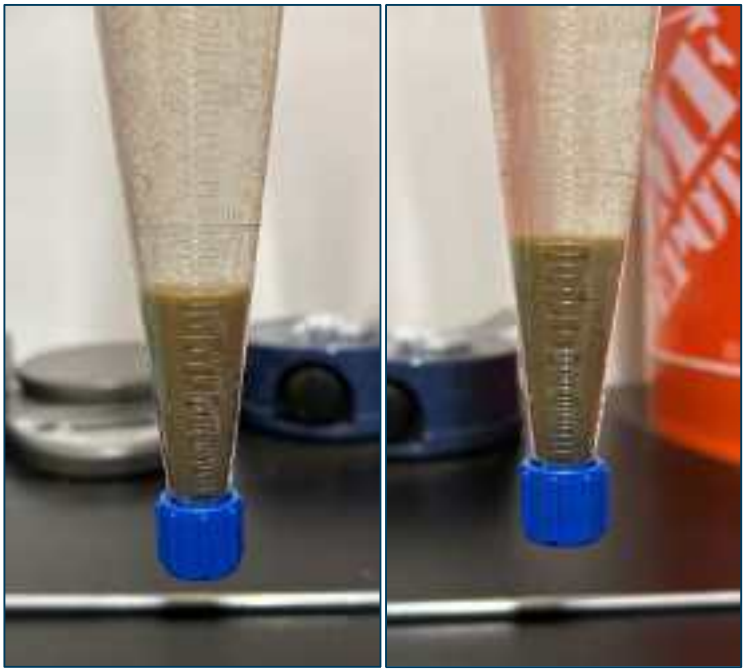

Exhibit d. Settleable Solids from Test 1 and Test 2

Exhibit e. pH measurements from Test 1 and Test 2

About ASRC Consulting & Environmental, LLC

ASRC Consulting & Environmental Services, LLC (ACES) is a subsidiary of ASRC Energy Services, LLC (AES). AES is a wholly owned subsidiary of the Alaska Native corporation Arctic Slope Regional Corporation (ASRC). With over 2,000 employees and more than 40 years of experience serving Alaska and working in the Arctic, AES has the expertise to handle every phase of an energy project regardless of scale or location. ACES is considered a Small Disadvantaged Business and Small Business Administration 8(a) program when subcontracting on a federal government contract and will count toward the prime contractor's Small Disadvantaged Business subcontracting goal.

Appendix E
Water Disposal Option Analysis
Based on
Alaska State Agency Requirements

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TECHNICAL MEMORANDUM

To: [Client Name, Title]

From: [Your Name, Title]

CC: [Reviewers, Stakeholders if any]

Date: [Month Day, Year]

Subject: Coalbed Methane (CBM) Produced Water Disposal Options

Project No.: 18322-01

Introduction and Available Disposal Options

The disposal of water produced from coalbed methane (CBM) extraction is subject to federal and state regulations, primarily focused on protecting surface water, groundwater, and soil resources. Based on research, the three primary options for disposal are:

- **Discharge to Land/Subsurface:** Allowed under Alaska Department of Environmental Conservation (ADEC) land application regulations, contingent on meeting soil and groundwater protection standards.
- **Discharge to Surface Water:** Allowed under the Alaska Pollutant Discharge Elimination System (APDES) Individual Permit, requiring compliance with stringent water quality standards and federal antidegradation policies.
- **Underground Injection (UIC Class II):** Specifically designed for oil and gas wastewater disposal, permitted by the Environmental Protection Agency (EPA) Region 10, and focused on non-endangerment of Underground Sources of Drinking Water (USDWs).

Water Quality Standards and Limitations

While drinking water standards may not apply, each option is governed by distinct water quality criteria and limitations to ensure environmental protection. Please refer to Table 1 Which summarizes the component-specific standards for each disposal method.

Table 1. Component-Specific Standards for each Disposal Method

Component	ADEC	APDES	UIC Class II
Total Dissolved Solids (TDS)	No numeric limit statewide; site-specific. TDS >500–1,000 mg/L often triggers review for long-term salt/heavy metal accumulation. Must not alter natural conditions or harm aquatic life.	No numeric limit statewide; must not alter natural conditions or harm aquatic life. Must not contaminate groundwater. Often limited to <500 mg/L for groundwater protection.	No specific numeric TDS limit but must be non-endangering to USDWs.
Sediment/Turbidity	It must not cause ponding, runoff, or sedimentation. BMPs required.	Must not reduce water quality by more than 5 NTU (natural condition) in clear water or 10% increase in naturally turbid waters.	Not regulated directly. Solids must not cause plugging or pressure issues in the formation.
Dissolved Oxygen (DO)	Not applicable unless water reaches surface.	≥7 mg/L for spawning; ≥5 mg/L for growth & migration of aquatic life.	Not applicable; injection zone is anaerobic.
Dissolved Inorganic Substances (Brine)	Must not exceed background groundwater limits. Often TDS and chloride-based limits apply. Sodium Adsorption Ratio (SAR) may be assessed for soil impacts.	No universal numeric limits. Na^+, Cl^-, SO_4^{2-} may be regulated to protect aquatic life. Discharge must not cause toxicity or salinity stress to aquatic organisms.	Brines are allowed only if injected into a permitted Class II well. Must not migrate to USDWs.
Petroleum Hydrocarbons	No visible sheen. Hydrocarbon content must not impact vegetation, soil infiltration, or groundwater.	<10 µg/L total aromatic hydrocarbons (TAH), <15 µg/L total aqueous hydrocarbons (TAqH), No visible sheen or film.	Typically prohibited unless formation is isolated. Must not affect USDWs.
Temperature	Temperature control is not regulated unless discharge reaches surface water or impacts groundwater temperature.	Must not exceed 20∘C for fish-bearing streams or cause temp increases >1∘C above natural.	Not regulated unless it impacts injection safety or formation integrity.
pH	Generally, the same: 6.5–8.5 SU to prevent groundwater impacts.	Must be between 6.5 and 8.5 SU. No sharp diurnal fluctuations allowed.	No specific EPA numeric standard but must be compatible with formation and casing/cement.
Other Toxic/Hazardous Substances	Must not exceed groundwater protection levels (e.g., ADEC Table C cleanup levels).	Must meet aquatic life criteria from Alaska Water Quality Standards and EPA CWA 304(a) criteria. Includes metals (As, Hg, Pb), ammonia, and others.	Must not endanger underground sources of drinking water.

Other Compositional and Operational Limitations

Beyond component-specific standards, other factors restrict the composition and operation of the disposal options:

- **Land/Subsurface Disposal (ADEC):** Designed to protect soil and shallow groundwater. Limits are often site-specific based on hydrogeology.
- **Surface Water (APDES Permit):** Must meet aquatic life protection standards. May require Whole Effluent Toxicity (WET) testing to ensure the entire effluent, not just individual components, is non-toxic.
- **Underground Injection (UIC Class II – EPA):** Focuses on isolation from drinking water aquifers (USDWs).
    - Injected fluids must be compatible with the formation.
    - Hazardous waste is strictly prohibited.
    - Corrosive fluids and solids can be restricted.
    - Well construction must meet rigorous EPA Class II standards.

Mixing Zone Option for Surface Water Discharge

A mixing zone can be applied for as part of an APDES permit application for discharge to surface waters. A mixing zone is a limited area or volume of the receiving water where the initial dilution occurs, and where water quality criteria are allowed to temporarily exceeded, provided that toxic substances do not cause mortality or morbidity in the immediate vicinity of the discharge.

Pre-Discharge Data Collection

The client will need to provide detailed site-specific and effluent data to support the mixing zone request. Key data requirements include:

- **Effluent Characterization:** A full suite of parameters (as listed in Section 2) must be sampled. Typically, this requires 3-6 samples over time, ideally covering seasonal variability.
- **Ambient Water Quality Data:** Background water quality of the receiving water body (e.g., TDS, pH, metals) collected upstream or away from the influence of the discharge.
- **Flow Data:** Accurate effluent flow data and receiving water flow data (e.g., 7Q10 low flow for a river).

- **Hydrologic/Hydraulic Modeling:** Modeling of the receiving water body (e.g., CORMIX) to predict the size, shape, and pollutant concentrations within the proposed mixing zone under critical flow conditions.

APDES Permit and Mixing Zone Approval Timeline

The mixing zone is not a separate permit but a component of the final APDES permit. The estimated time for ADEC to approve a mixing zone (as part of the final APDES permit) is 6-12 months.

This timeline is highly variable and depends on:

- **Quality and Completeness of Data Submitted:** Submitting a robust and complete application is essential.
- **Complexity of the Receiving Water:** A simple flowing river is often easier to model than a stagnant lake or an estuarine environment.
- **Public Interest/Environmental Sensitivity:** High public interest or discharge into sensitive environments (e.g., critical habitat) may require more extensive review.
- **Consultation Triggers:** Whether federal consultations, such as those under the Endangered Species Act (ESA) or Historic Preservation (SHPO), are triggered which can extend the review timeline due to required coordination with federal and state agencies.

Evaluation of Disposal Options: Short- and Long-Term Feasibility, Cost, and Risk

When evaluating disposal options, it is important to consider both the short and long-term of each method. Each option varies in terms of permitting complexity, capital and operational costs, environmental and regulatory risks, and technical feasibility.

- **Land/Subsurface Disposal:** Short term, this option is the easiest and quickest to permit, making it ideal for small, short-duration projects with lower capital costs and manageable environmental risk. However, long-term use can become less feasible due to land area requirements, potential soil degradation, and increase risk of ground water contamination. Potential system replacement and ongoing maintenance can raise long-term costs.

- **Surface Water Disposal:** Short term use can be challenging and costly due to strict water quality standards, permitting, and the need of advanced treatment systems. This can make it less feasible for high-volume discharges over a 12-month timeframe. Long term can be feasible, but it can involve high and continuous operational costs, regulatory risks, as well as intense monitoring. Permitting and treatment costs may balance out over 20 years, but UIC injections are often more financially and operationally favorable for sustained disposal.

- **UIC Class II:** This option is not practical for short-term use due to a lengthy permitting process, high upfront costs, and long construction timelines. However, long term use is the industry standard for disposing of high-volume produced water. The initial costs will be high, and overtime operational costs are low and stable. Strong regulatory controls and monitoring can make it a cost-effective and reliable solution over the life of the project.

Another thing to note is that the project area may have sensitive groundwater aquifers, glacial sediments, and interconnected surface waters. Working with ADEC and possibly EPA Region 10 for permitting while UIC wells may fall under AOGCC jurisdiction.

Conclusion

Selecting the right water disposal method is critical to project success. The three options, ADEC land/subsurface discharge, APDES surface water discharge, and UIC Class II injection offers trade-offs in terms of permitting timelines, upfront and operational costs, environmental risk and long-term viability.

For small-scale or short-term projects, land/subsurface disposal under ADEC presents the fastest and most cost-effective path (provided site conditions are favorable). Surface water discharge is known to be more complex and costly upfront but may be feasible with advanced treatment and sufficient lead time for permitting purposes. UIC Class II injection is the industry standard for long-term, high-volume disposal due to its lower operational costs over time and its regulatory reliability. It is not practical for short-term use.

Given the project area's sensitive groundwater, glacial soils, and surface water connections, early engagement with ADEC, EPA Region 10, and AOGCC are strongly recommended to align permitting pathways and avoid delays. Identifying the preferred disposal method early will help optimize capital planning, ensure regulatory compliance, and reduce long-term operational risk.

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Appendix F
Pioneer Natural Resources, LLC
Coal Desorption Report

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Hampton, Waechter, & Associates, LLC

HW&A Coalbed Methane Specialists

Coal Desorption Report

For

Pioneer Natural Resources, Inc.

(formerly Evergreen Resources, Inc.)

Alaska Core Holes:

203209 **Kashwitna Lake #1 (Sec 7, T 20 N, R 4 W, Mat-Su Borough)** 29106
203208 **Sheep Creek #1 (Sec 20, T 22 N, R 4 W, Mat-Su Borough)** 29105
203206 **Houston Pit #1 (Sec 20, T 18 N, R 3 W, Mat-Su Borough)** 29103
203205 **Little Su #1 (Sec 36, T 19 N, R 1 E, Mat-Su Borough)** 29102
204057 **Slats #1 (Sec 17, T 17 N, R 2 E, Mat-Su Borough)** 29104
Willow Fishook #1 (Sec 3, T 19 N, R 4 W, Mat-Su Borough)

Hampton, Waechter & Associates, LLC
Coalbed Methane Desorption Specialists
11 Inverness Way South
Englewood, CO 80112
(303) 825-7140
www.hwa-cbm.com

February 2005

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Introduction

In December of 2003, Hampton, Waechter & Associates, LLC was contracted by Evergreen Resources, Inc. to conduct coal desorption tests on five wireline core holes in Mat-Su Borough near Wasilla, Alaska. Coring commenced in January 2004 and was completed in May 2004. One of the originally planned wells, the Willow Fishook #1, was abandoned in alluvium at 345 feet total depth but replaced by another well. In all, forty-seven coals and carbonaceous shales were canned, plus one gassy sandstone canned at the client's request. Layne Christiansen performed the coring. The field desorption work was conducted by Brian Reddick, David Schwantes, and Luke Schwantes.

There is a spreadsheet (Evergreen Resources Alaska Desorption Summary.xls) accompanying this report that summarizes the data for the coal core samples and the gas content measured. Several gas analyses were run on the samples taken. The results of the analyses can be found in the spreadsheet (Evergreen Alaska Gas Analyses.xls)

Individual desorption reports are included as Excel files (i.e. DZc-ES-01.xls and DZc-EHP-01.xls). These files have the report page on the far left tab of the workbook and the graphs on tabs to the right.

All data contained in printed copies of this report are also provided on CD in digital format (MS Excel and MS Word).

Procedures

Coal samples were collected at the wellsite from wireline-retrieved core, described, and placed into desorption canisters. Desorption canisters were kept in a water bath on location at reservoir temperature during the collection of initial readings for estimating lost gas and for the remainder of the readings. It is common practice to conduct desorption measurements at reservoir temperatures, so as to mimic desorption under reservoir conditions as closely as possible. HWA followed this standard procedure on the Evergreen Alaska project. Reservoir temperature estimations were based upon plots of bottom-hole temperatures (with depth) from data provided by the client. Desorption readings were continued until the cumulative gas curve flattened to near zero gas increase with time, or until the client requested termination of desorption.

After desorption was complete, residual gas from crushed sample splits of the cores was measured for the majority of the samples. Some of the sample splits were sent to Dr. Marc Bustin, a coal petrologist at University of British Columbia, for comprehensive analytical testing. The tests included adsorption isotherms, equilibrium moisture and ash, vitrinite reflectance, maceral composition, macroscopic coal descriptions, and cleat mineralogy (X-ray diffraction and macroscopic descriptions). Gas samples were analyzed at Isotech Laboratories for gas composition and for carbon and deuterium isotope analysis.

Both a polynomial fit and a linear fit were used to project lost gas curves. Gas content derived from using a polynomial fit for lost gas estimation usually gives the best fit to the data and results in somewhat higher lost gas values. Historically the CBM industry has used a linear fit for projecting lost gas (Bureau of Mines Direct Method, Reference #1). HW&A has shown in recent publications (see Reference #4 below) a polynomial fit for lost gas better represents the data in most cases. Several of our publications, which compare the results of the two methods, are listed below.

References on Desorption Techniques, Field Data Collection, And Lost Gas Projections:

1. Diamond, W.P., and J.R. Levine, 1981, Direct method determination of the gas content of coal-Procedures and results: U.S. Bureau of Mines Report of Investigations 8515, 36 p.

2. Bertard, C., B. Bruyet, and J. Gunther, 1970, Determination of desorbable gas concentration of coal (Direct Method): International Journal of Rock Mechanics and Mining Science, v. 7, p. 43–65.

3. Waechter, N.B., G.L. Hampton, S.D. Schwochow, and John P. Seidle, 2004, "Accurate Gas Content Analysis Improves Coalbed Gas Resource Estimation", World Oil, August 2004

4. Waechter, N.B., G.L. Hampton, J.C. Shipps, and John P. Seidle, 2004, "Comparison of Lost Gas Projections in Coalbed Methane", Poster Session at Rocky Mountain Section AAPG, Denver, Colorado.

5. Waechter, N.B., G.L. Hampton, and J.C. Shipps, 2004, "Overview of Coal and Shale Gas Measurement: Field and Laboratory Procedures" in Proceedings of the 2004 International Coalbed Methane Symposium, May 2004, The University of Alabama, Tuscaloosa, Alabama.

HWA would be happy to furnish digital copies of any of our publications to our clients.

Gas Content

In the five core holes, a total of thirty six coals, seven carbonaceous shales, four lignites, and one sandstone were collected and canned. Gas contents of the coals, carb shales, and lignites are given in Table 1 by desorption canister. Additional data can be found in the Excel spreadsheet "Evergreen Resources Alaska Desorption Summary.xls". The estimated residual gas content is based upon graphic projections of gas content to infinite time. Residual gas was measured on crushed splits on all but seven of the forty eight samples canned. These residual gas values are also given in the individual desorption files. Gas contents are discussed on an as-received basis (ARB) unless noted otherwise.

Table 1 shows total gas on an as-received basis (ARB) with projected residual gas and measured residual gas. Also in this table total gas is compared using a polynomial fit for lost gas and a linear fit for lost gas. Table 2 compares gas contents on an as-received basis with gas contents on a dry ash-free basis (DAF).

Table 1. Gas Content of Coals and Carbonaceous Shales by Well

Canister #	Depth (log) (ft)	Zone	POLYNOMIAL FIT FOR LOST GAS Bulk Sample, As-received Basis (ARB) Projected Residual Gas (scft/ton)	Measured Residual Gas (scft/ton)	Total Gas (Lost + Measured + Projected Residual Gas) scft/ton	Total Gas (Lost + Measured + Measured Residual Gas) scft/ton	LINEAR FIT FOR LOST GAS Bulk Sample, As-received Basis (ARB) Total Gas (Lost + Measured + Projected Residual Gas) scft/ton	Total Gas (Lost + Measured + Measured Residual Gas) scft/ton	Lithology
EKL-01	1021.0	Sterling	0.0	N/A	0.0		0.0		Lignite
		Averages:	0.0	N/A	0.0	N/A	0.0	N/A	
ESC-01	1018.0	Sterling	0.0	N/A	0.5		0.3		Lignite
ESC-02	1121.0	Sterling	2.3	N/A	7.6		7.6		Lignite
ESC-03	1199.0	Sterling	1.2	N/A	10.0		10.4		Lignite
		Averages:	1.2	N/A	6.2	N/A	6.1	N/A	
EHP-01	293.0	Tyonek	7.9	14.1	33.6	40.0	33.4	39.0	Coal
EHP-03	382.7	Tyonek	8.7	10.1	54.2	55.6	52.1	53.4	Coal
EHP-04	602.5	Tyonek	2.5	7.5	40.4	51.6	45.7	49.0	Coal
EHP-05	827.0	Tyonek	34.2	32.2	114.2	122.1	113.3	121.3	Coal
EHP-06	878.0	Tyonek	55.0	57.8	132.3	145.1	142.2	144.7	Coal
EHP-07	937.0	Tyonek	5.7	10.2	83.1	87.7	79.2	81.7	Coal
EHP-08	1100.5	Tyonek	48.5	60.8	162.3	173.5	160.8	173.1	Coal
EHP-09	1112.3	Tyonek	32.5	35.6	163.3	166.4	163.8	165.0	Coal
EHP-10	1157.6	Tyonek	20.4	33.4	146.9	154.0	144.0	152.0	Coal
EHP-11	1273.5	Tyonek	27.9	35.5	128.4	134.0	124.0	140.6	Coal
		Averages:	23.9	31.0	107.6	115.0	105.7	113.1	
ELS-01	322.0	Tyonek	21.9	39.8	53.1	62.0	51.0	63.9	Coal
ELS-02	1970.4	Chickaloon	2.8	10.7	60.0	68.7	52.0	61.7	Carb Shale
ELS-03	2000.9	Chickaloon	8.8	21.6	146.7	160.3	126.8	138.3	Carb Shale
ELS-04	2098.3	Chickaloon	3.4	12.4	97.7	106.7	99.6	99.4	Carb Shale
		Averages:	8.9	23.9	89.4	104.4	83.1	90.3	
ES-01	500.4	Tyonek	6.1		19.1		18.8		Coal
ES-02	578.0	Tyonek	14.0		37.9		37.7		Coal
ES-03	733.7	Tyonek	13.8	19.7	57.6	63.4	56.8	62.7	Coal
ES-04	775.8	Tyonek	37.0	83.1	88.8	108.9	88.3	104.5	Coal
ES-05	845.4	Tyonek	36.6	66.0	97.8	127.1	97.6	129.9	Coal
ES-06	965.0	Tyonek	10.5	23.8	45.3	68.4	62.1	65.4	Carb Shale
ES-07	1090.0	Tyonek	29.3	76.3	108.8	155.0	106.7	153.7	Coal
ES-08	1160.6	Tyonek	23.9	38.1	141.8	155.6	138.7	150.9	Coal
ES-09	1215.5	Tyonek	25.9	54.3	125.3	153.4	122.7	151.1	Coal
ES-10	1322.0	Tyonek	23.1	28.9	116.5	122.4	114.4	120.3	Coal
ES-11	1408.0	Tyonek	49.0	81.9	157.4	190.2	154.1	187.1	Coal
ES-12	1471.2	Tyonek	48.7	62.2	199.5	204.0	180.0	202.5	Coal
ES-13	1700.1	Tyonek	39.3	87.5	166.8	214.4	191.6	209.9	Coal
ES-14	1736.8	Tyonek	29.9	42.5	182.2	194.8	190.9	202.5	Coal
ES-15	1801.5	Tyonek	34.1	54.0	191.5	211.8	188.8	208.7	Coal
ES-16	1951.8	Tyonek	102.7	131.1	229.0	257.4	228.2	276.6	Coal
ES-17	2004.8	Tyonek	38.8	68.5	183.9	199.8	162.1	196.8	Coal
ES-18	2055.1	Tyonek	69.8	97.8	206.5	234.3	205.4	233.1	Coal
ES-19	2113.0	Tyonek	78.6	102.6	236.9	260.8	236.5	260.5	Coal
ES-20	2210.5	Tyonek	36.3	39.5	211.6	211.6	209.3	209.2	Coal
ES-21	2283.0	Tyonek	5.7	24.8	91.4	110.0	90.0	109.2	Carb Shale
ES-22	2302.0	Tyonek	110.1	115.2	269.5	274.4	268.6	273.5	Coal
ES-23	2429.0	Tyonek	62.3	62.9	229.8	230.3	227.7	228.2	Coal
ES-24	2529.3	Tyonek	9.0	13.6	116.6	121.1	112.2	110.7	Carb Shale
ES-25	2624.0	Tyonek	109.3	119.8	273.2	288.7	273.0	288.5	Coal
ES-26	2682.0	Tyonek	34.3	40.1	190.6	196.5	188.3	194.1	Carb Shale
ES-27	2757.9	Tyonek	41.3	53.8	230.0	242.5	224.2	236.8	Coal
ES-28	2858.0	Tyonek	54.4	42.6	213.6	221.2	209.7	218.0	Coal
ES-29	2901.1	Tyonek	38.9	56.4	218.3	234.5	217.1	233.5	Coal
		Averages:	42.9	62.3	180.3	188.0	178.4	186.0	

On an as-received basis, the total gas content of the coals (with measured residual gas) for all the wells varies between 0.0 and 288.7 scft/ton using a polynomial fit for lost gas and 0.0 to 288.5 scft/ton using a linear fit for lost gas. The highest gas contents are observed in the Slats well (averaging 188 scft/ton total gas, coals and carb shales). At the similar depths, coals from the Houston Pit well had similar gas contents to the Slats well, but this well was not drilled as deep as the Slats well. Coals from the Kashwitna Lake and Sheep Creek wells had the lowest gas contents. Table 3 shows comparison of gas content by lithology: coals, carbonaceous shales, and lignites. Coals averaged 171.0 scft/ton on an as-received basis and 269.7 scft/ton on a dry ash-free basis.

Table 2. Comparison of ARB and DAF Gas Contents by Well

			POLYNOMIAL FIT FOR LOST GAS				
			Bulk Sample, As-recieved Basis (ARB)		Dry Ash-Free Basis (DAF)		
Canister #	Driller's Depth (top) (ft)	Zone	Total Gas (Lost + Measured + Projected Residual Gas) scft/ton	Total Gas (Lost + Measured + Measured Residual Gas) scft/ton	Total Gas (Lost + Measured + Projected Residual Gas) scft/ton	Total Gas (Lost + Measured + Measured Residual Gas) scft/ton	Lithology
EKL-01	1021.0	Sterling	0.0		0.0		Lignite
		Averages:	**0.0**	N/A	N/A	N/A	
ESC-01	1018.0	Sterling	0.5		0.7		Lignite
ESC-02	1121.0	Sterling	7.6		12.3		Lignite
ESC-03	1199.0	Sterling	10.6				Lignite
		Averages:	**6.2**	N/A	**6.5**	N/A	
EHP-01	293.0	Tyonek	33.6	40.0	64.9	77.3	Coal
EHP-03	582.7	Tyonek	54.2	55.6	130.1	133.4	Coal
EHP-04	602.5	Tyonek	46.4	51.6	110.6	123.1	Coal
EHP-05	827.0	Tyonek	114.2	122.1	204.1	218.3	Coal
EHP-06	838.0	Tyonek	142.3	145.1	184.3	187.8	Coal
EHP-07	937.0	Tyonek	83.1	87.7	208.2	219.7	Coal
EHP-08	1104.2	Tyonek	161.3	173.5	224.8	241.8	Coal
EHP-09	1112.3	Tyonek	165.3	166.4	270.6	272.4	Coal
EHP-10	1157.6	Tyonek	146.9	154.0	273.1	286.2	Coal
EHP-11	1275.5	Tyonek	128.4	154.0	261.0	313.0	Coal
		Averages:	**107.6**	**115.0**	**193.2**	**207.3**	
ELS-01	322.0	Tyonek	53.1	82.0	93.6	144.4	Coal
ELS-02	1970.0	Chickaloon	60.0	68.7	222.0	254.3	Carb Shale
ELS-03	2000.0	Chickaloon	146.7	160.3	489.7	534.9	Carb Shale
ELS-04	2038.5	Chickaloon	97.7	106.5	268.6	292.8	Carb Shale
		Averages:	**89.4**	**104.4**	**268.5**	**306.6**	
ES-01	500.4	Tyonek	19.1				Coal
ES-02	578.0	Tyonek	37.9				Coal
ES-03	733.7	Tyonek	57.6	63.4	119.5	131.7	Coal
ES-04	779.8	Tyonek	88.8	104.9	111.5	131.6	Coal
ES-05	841.4	Tyonek	97.8	127.1	135.6	176.3	Coal
ES-06	965.0	Tyonek	65.1	68.4	205.0	215.4	Carb Shale
ES-07	1091.0	Tyonek	108.8	155.8	194.1	278.0	Coal
ES-08	1165.6	Tyonek	141.4	153.6	199.2	216.4	Coal
ES-09	1237.7	Tyonek	125.1	153.4	190.6	233.9	Coal
ES-10	1322.0	Tyonek	116.5	122.4	237.0	248.9	Coal
ES-11	1408.9	Tyonek	157.4	190.3	232.8	281.6	Coal
ES-12	1471.2	Tyonek	190.5	204.0	255.1	273.2	Coal
ES-13	1700.1	Tyonek	166.1	214.4	308.4	398.0	Coal
ES-14	1726.0	Tyonek	202.2	204.8	318.0	322.0	Coal
ES-15	1801.5	Tyonek	191.1	211.0	301.6	333.0	Coal
ES-16	1951.0	Tyonek	229.0	257.4	281.7	316.7	Coal
ES-17	2004.0	Tyonek	165.9	199.6	286.4	344.7	Coal
ES-18	2055.1	Tyonek	206.5	234.3	291.8	331.0	Coal
ES-19	2113.0	Tyonek	236.9	260.8	294.6	324.4	Coal
ES-20	2210.5	Tyonek	211.6	211.6	373.3	373.3	Coal
ES-21	2283.0	Tyonek	91.4	110.6	236.1	285.6	Carb Shale
ES-22	2302.0	Tyonek	269.3	274.4	345.6	352.2	Coal
ES-23	2429.0	Tyonek	229.8	230.3	311.8	312.5	Coal
ES-24	2529.3	Tyonek	116.6	121.1	339.5	352.7	Carb Shale
ES-25	2624.0	Tyonek	275.2	288.7	322.3	338.1	Coal
ES-26	2682.0	Tyonek	190.6	196.5	484.4	499.4	Carb Shale
ES-27	2757.9	Tyonek	230.0	242.5	332.4	350.5	Coal
ES-28	2858.0	Tyonek	213.0	221.2	397.5	412.9	Coal
ES-29	2901.3	Tyonek	218.3	254.7	404.2	471.7	Coal
		Averages:	**160.3**	**188.0**	**278.2**	**307.6**	

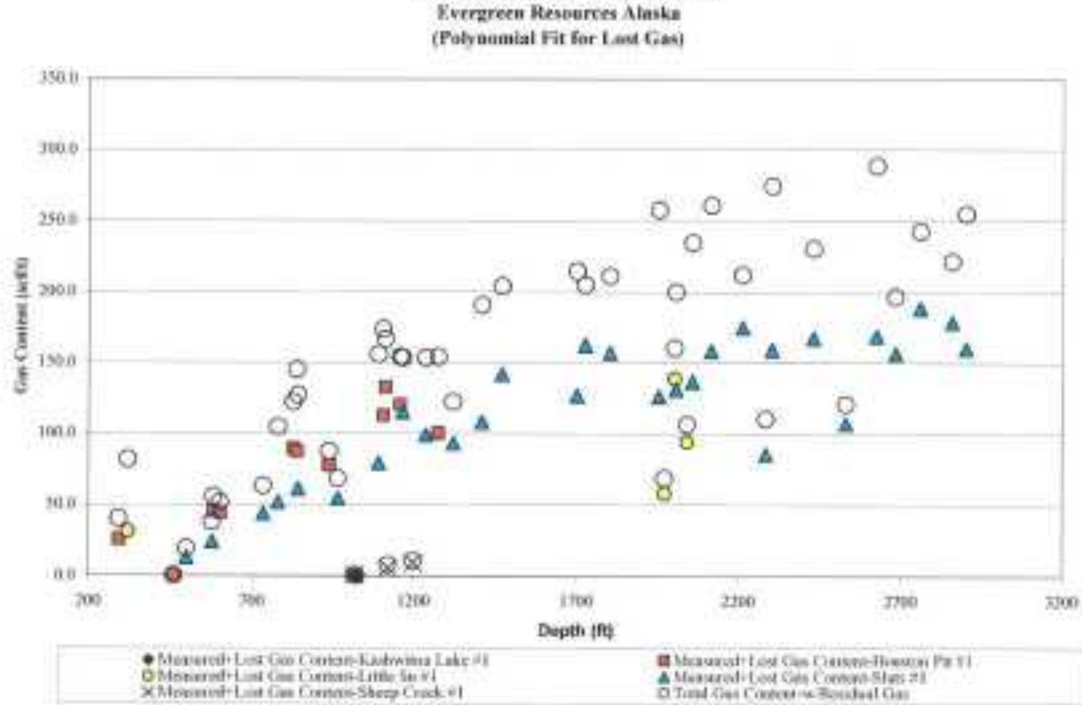
Table 3. Comparison of ARB and DAF Gas Contents by Lithology

			POLYNOMIAL FIT FOR LOST GAS				
			Bulk Sample, As-received Basis (ARB)		Dry Ash-Free Basis (DAF)		
Canister #	Driller's Depth (top) (ft)	Zone	Total Gas (Lost + Measured + Projected Residual Gas) scft/ton	Total Gas (Lost + Measured + Measured Residual Gas) scft/ton	Total Gas (Lost + Measured + Projected Residual Gas) scft/ton	Total Gas (Lost + Measured + Measured Residual Gas) scft/ton	Lithology
EHP-01	293.0	Tyonek	33.6	40.0	64.9	77.3	Coal
EHP-03	582.7	Tyonek	54.2	55.6	130.1	133.4	Coal
EHP-04	602.5	Tyonek	46.4	51.6	110.6	123.1	Coal
EHP-05	827.0	Tyonek	114.2	122.1	204.1	218.3	Coal
EHP-06	838.0	Tyonek	142.3	145.1	184.3	187.8	Coal
EHP-07	937.0	Tyonek	83.1	87.7	208.2	219.7	Coal
EHP-08	1104.2	Tyonek	161.3	173.5	224.8	241.8	Coal
EHP-09	1112.3	Tyonek	165.3	166.4	270.6	272.4	Coal
EHP-10	1157.6	Tyonek	146.9	154.0	273.1	286.2	Coal
EHP-11	1275.5	Tyonek	128.4	154.0	261.0	313.0	Coal
ELS-01	322.0	Tyonek	53.1	82.0	93.6	144.4	Coal
ES-01	500.4	Tyonek	19.1	NA	NA	NA	Coal
ES-02	578.0	Tyonek	37.9	NA	NA	NA	Coal
ES-03	733.7	Tyonek	57.6	63.4	119.5	131.7	Coal
ES-04	779.8	Tyonek	88.8	104.9	111.5	131.6	Coal
ES-05	841.4	Tyonek	97.8	127.1	135.6	176.3	Coal
ES-07	1091.0	Tyonek	108.8	155.8	194.1	278.0	Coal
ES-08	1165.6	Tyonek	141.4	153.6	199.2	216.4	Coal
ES-09	1237.7	Tyonek	125.1	133.4	190.6	233.9	Coal
ES-10	1322.0	Tyonek	116.5	122.4	237.0	248.9	Coal
ES-11	1408.9	Tyonek	157.4	190.3	232.8	281.6	Coal
ES-12	1471.2	Tyonek	190.5	204.0	255.1	273.2	Coal
ES-13	1700.1	Tyonek	166.1	214.4	308.4	398.0	Coal
ES-14	1726.0	Tyonek	202.2	204.8	318.0	322.0	Coal
ES-15	1801.5	Tyonek	191.1	211.0	301.6	333.0	Coal
ES-16	1951.0	Tyonek	229.0	257.4	281.7	316.7	Coal
ES-17	2004.0	Tyonek	165.9	199.6	286.4	344.7	Coal
ES-18	2055.1	Tyonek	206.3	234.3	291.8	331.0	Coal
ES-19	2113.0	Tyonek	236.9	260.8	294.6	324.4	Coal
ES-20	2210.5	Tyonek	211.6	211.6	373.3	373.3	Coal
ES-22	2302.0	Tyonek	269.3	274.4	345.6	352.2	Coal
ES-23	2429.0	Tyonek	229.8	230.3	311.8	312.5	Coal
ES-25	2624.0	Tyonek	275.2	288.7	322.3	338.1	Coal
ES-27	2757.9	Tyonek	230.0	242.5	332.4	350.5	Coal
ES-28	2858.0	Tyonek	213.0	221.2	397.5	412.9	Coal
ES-29	2901.3	Tyonek	218.3	254.7	404.2	471.7	Coal
		Averages:	**147.6**	**171.0**	**243.2**	**269.7**	
ELS-02	1970.0	Chickaloon	60.0	68.7	222.0	254.3	Carb Shale
ELS-03	2000.0	Chickaloon	146.7	160.3	489.7	534.9	Carb Shale
ELS-04	2038.5	Chickaloon	97.7	106.5	268.6	292.8	Carb Shale
ES-06	965.0	Tyonek	63.1	68.4	205.0	215.4	Carb Shale
ES-21	2283.0	Tyonek	91.4	110.6	236.1	285.6	Carb Shale
ES-24	2529.3	Tyonek	116.6	121.1	339.5	352.7	Carb Shale
ES-26	2682.0	Tyonek	190.6	196.5	484.4	499.4	Carb Shale
		Averages:	**109.7**	**118.9**	**320.8**	**347.9**	
EKL-01	1021.0	Sterling	0.0	NA	0.0	NA	Lignite
ESC-01	1018.0	Sterling	0.5	NA	0.7	NA	Lignite
ESC-02	1121.0	Sterling	7.6	NA	12.3	NA	Lignite
ESC-03	1199.0	Sterling	10.6	NA	NA	NA	Lignite
		Averages:	**4.7**	**NA**	**4.3**	**NA**	

Gas Content vs. Depth

Figure 1 shows changes in gas content with depth of the coals. Lost gas estimates in the coals averaged 10% of the total gas. The average time for lost gas was 18 minutes. Residual gas averaged 28% of total gas, which is a higher percentage of residual gas than is present in most coals. The Alaska coals in this area had low reservoir temperatures, in part related to very low mean annual surface temperatures. Since sorptive capacity of a coal increases with decreasing reservoir temperature, the low reservoir temperatures in this area would allow the coals to retain a higher percentage of residual gas at atmospheric pressure. Consequently these coals would be expected to retain a higher percentage of gas that could not be produced at existing reservoir temperatures. Technically, residual gas is defined as the amount of gas a coal is capable of retaining at atmospheric pressure in a 100% atmosphere of that gas (Reference #2). The term "residual gas" is commonly used by industry to mean the amount of gas left in a coal when desorption slows down to some arbitrarily defined rate (Waechter et al, 2004, reference #3). On the samples collected latest from the Slats well, crushed residual gas was measured before the desorption curve flattened completely, so some of the coals from this well appeared to have a higher percentage of "residual gas".

Figure 1. Gas Content vs. Depth: all wells



It can be seen that the gas contents of the Kashwitna Lake, Sheep Creek and Little Su wells are anomalously low for their depths. Looking at sample lithology (Figure 2) and coal rank (Figure 3) helps explain some of these observations. The coals from the Kashwitna Lake and Sheep Creek wells are lignites, which typically contain little gas. The Little Su well,

Figure 2. Gas Content vs. Depth: by Lithology:

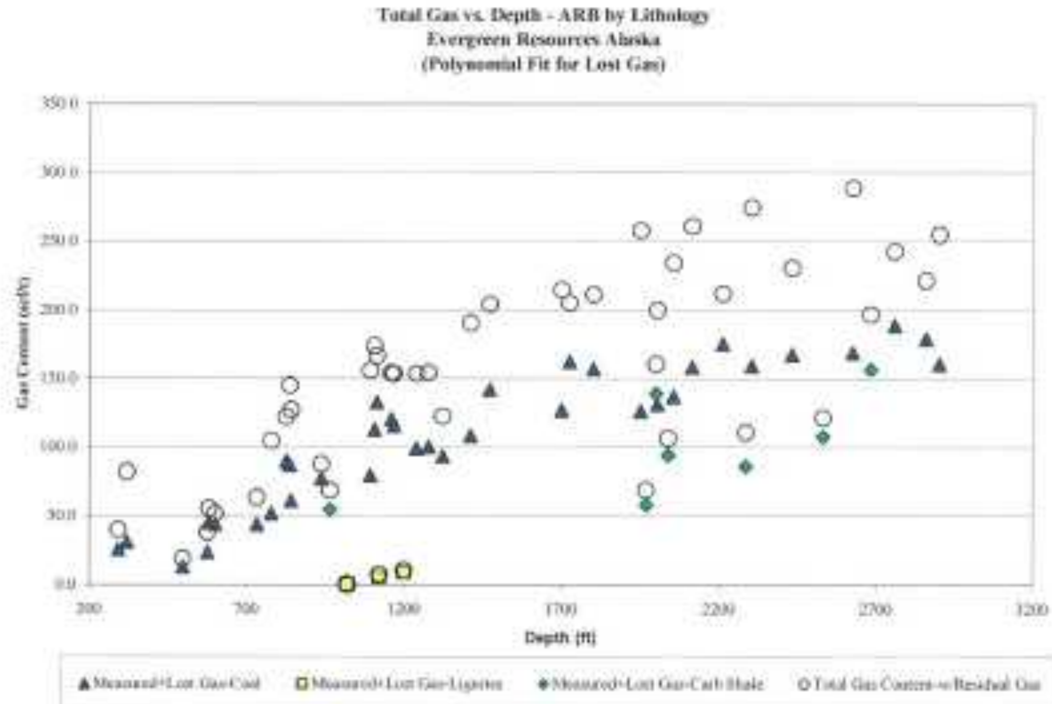
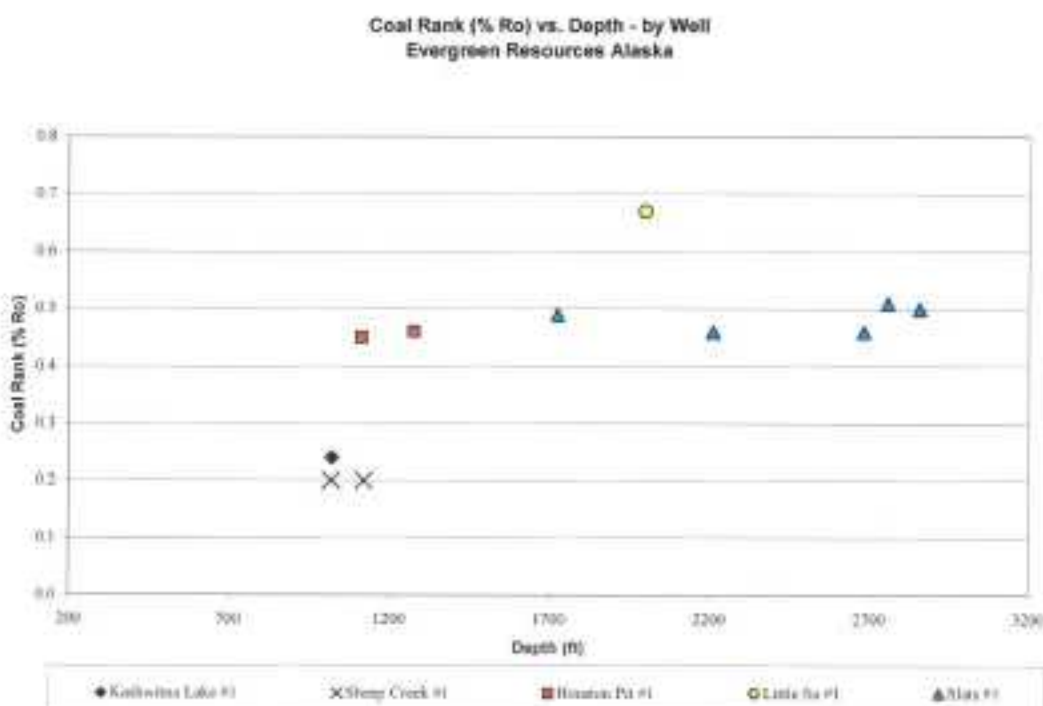


Figure 3. Coal Rank vs. Depth:

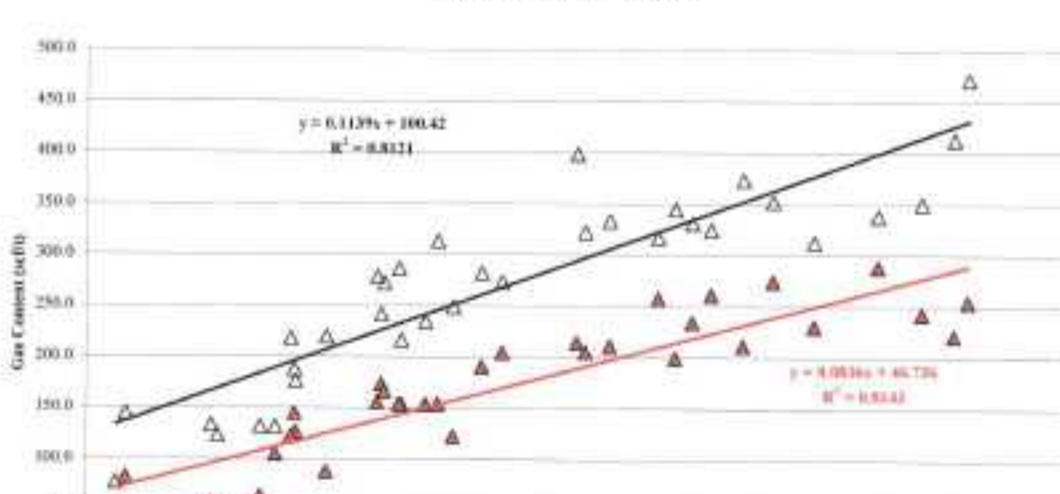


on the other hand has coals of much higher rank: hi-volatile bituminous B with a vitrinite reflectance of 0.67%. Coals of this rank are capable of generating thermal gas, but obviously some geologic factor has influenced the gas content of these coals. Brian Reddick said that the Little Su well was closer to the known high-rank coals of Anthracite Ridge, than the rest of the wells, which explains the rank anomaly but not the gas content anomaly. Flushing by geothermally heated water is one way that coals can become depleted in gas, but a study of the local geology would be needed for more definitive answers.

In the Houston Pit and Slats wells, coal rank shows only a slight increase over the last 1700 feet of depth (Figure 3). This may explain why the coals seem to show a relatively small increase in gas content beyond 1700 feet for these two wells (Figures 1 and 2).

Because of the high ash contents of many of the coals, gas contents on a dry ash-free basis can be significantly higher than on an as-received basis (Table 3). Comparing the gas contents of just the coals, on both an as-received basis and a dry ash-free basis, brings out a clearer relationship for changes in gas content with depth (Figure 4).

Figure 4. Total Gas vs. Depth: Coals Only, as-received basis and dry ash-free basis.



Dry ash-free gas contents on coals with more than 40% ash and in carb shales (>50% ash) must be viewed with some suspicion. Total gas in these sorts of rocks may include other gas phases besides those sorbed upon organic material.

Gas Composition

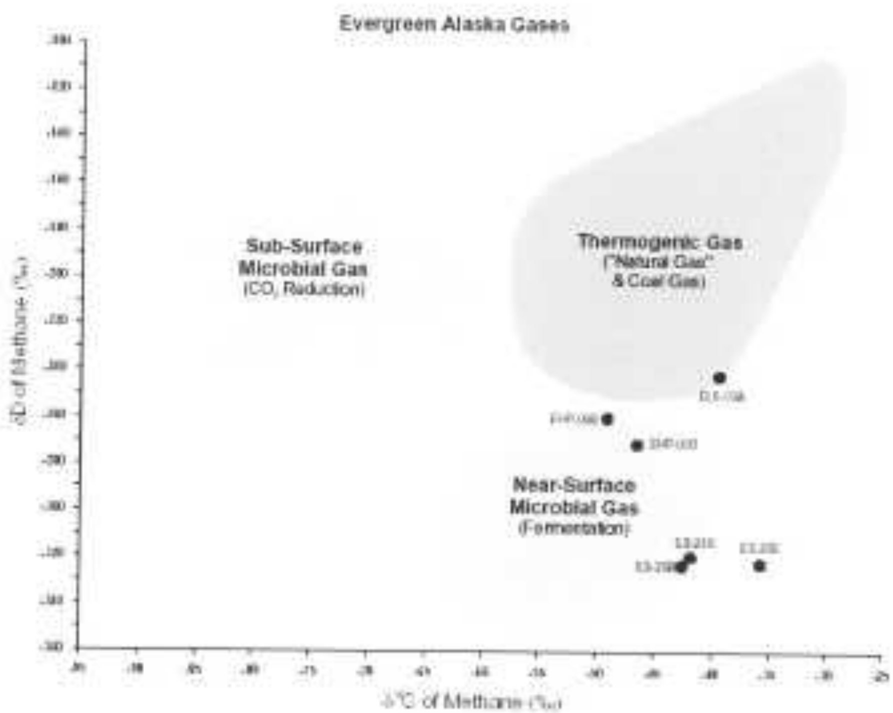
Gas samples were taken from the Houston Pit, Little Su, and Slats wells. Three to four gas samples were taken over time from the desorption canisters to determine changes in gas composition with desorption time. These samples were analyzed at Isotech Laboratories for gas composition and for isotopic composition. The gas compositions are given below in Table 4 as normalized mole percents with air contaminants subtracted. Gases from the Houston Pit and Slats wells are all over 99% methane with only traces of C2 and heavier gases. The one gas sample taken from the Little Su well was a wet gas with over 10% C2 and 2%C3, as would be expected for a higher rank coal with thermogenic gas potential.

Table 4. Gas Composition of Coals with Averages

Canister #	Normalized Mole% (with Air Subtracted)					
	N_2	CO_2	C1	C2	C3	I-C4
EHP-07A	0.00	0.09	99.72	0.15	0.01	0.00
EHP-07B	0.00	0.07	99.68	0.20	0.03	0.01
EHP-07C	0.00	0.10	99.38	0.39	0.06	0.01
EHP-09A	0.00	0.08	99.84	0.06	0.00	0.00
EHP-09B	0.00	0.06	99.86	0.07	0.01	0.00
EHP-09C	0.00	0.08	99.85	0.07	0.00	0.00
Averages Houston Pit Well:	**0.00**	**0.08**	**99.72**	**0.16**	**0.02**	**0.00**
ELS-03A	0.00	0.06	86.61	10.66	2.09	0.37
Averages Little Su Well:	**0.00**	**0.06**	**86.61**	**10.66**	**2.09**	**0.37**
ES-14A	0.00	0.07	99.71	0.21	0.01	0.00
ES-14C	0.00	0.06	99.64	0.29	0.01	0.00
ES-14D	0.00	0.07	99.57	0.32	0.01	0.00
ES-20A	0.00	0.08	99.65	0.22	0.03	0.00
ES-20B	0.00	0.06	99.60	0.27	0.03	0.00
ES-20C	0.00	0.06	99.50	0.36	0.06	0.01
ES-20D	0.00	0.07	99.32	0.52	0.07	0.01
ES-24A	0.00	0.10	99.65	0.22	0.03	0.00
ES-24B	0.00	0.06	99.54	0.33	0.05	0.01
ES-24D	0.00	0.16	98.57	0.99	0.19	0.04
ES-26A	0.00	0.07	99.51	0.35	0.05	0.01
ES-26B	0.00	0.08	99.43	0.41	0.07	0.01
ES-26C	0.00	0.07	99.42	0.42	0.07	0.01
ES-26D	0.00	0.08	99.30	0.51	0.08	0.01
ES-27A	0.00	0.11	99.55	0.30	0.04	0.00
ES-27B	0.00	0.06	99.50	0.36	0.04	0.01
ES-27C	0.00	0.14	99.39	0.40	0.05	0.01
ES-27D	0.00	0.12	99.32	0.48	0.06	0.01
ES-28A	0.00	0.07	99.44	0.44	0.04	0.00
ES-28B	0.00	0.06	99.36	0.51	0.04	0.00
ES-28C	0.00	0.07	99.04	0.81	0.07	0.01
ES-28D	0.00	0.07	99.04	0.79	0.07	0.01
Averages Slats Well:	**0.00**	**0.08**	**99.41**	**0.43**	**0.05**	**0.01**

Figure 5 shows the results of the isotopic analysis of six of the gas samples. The isotopes analyzed were deuterium and C_{13}, both from the methane molecule. Five of the gas samples had isotopic compositions in the range of near-surface biogenic gas, an interpretation reinforced by gas sample compositions of nearly pure methane from the same wells (Houston Pit and Slats). The one sample from the Little Su well had an isotopic composition in the range of thermogenic gas. The gas from this sample was a wet gas, which reinforces the isotopic interpretation of a thermogenic gas for this sample. The samples close to the borders of the fields shown in Figure 5 could be interpreted as mixing of biogenic and thermally derived gas, or alteration of thermal gas by biogenic processes.

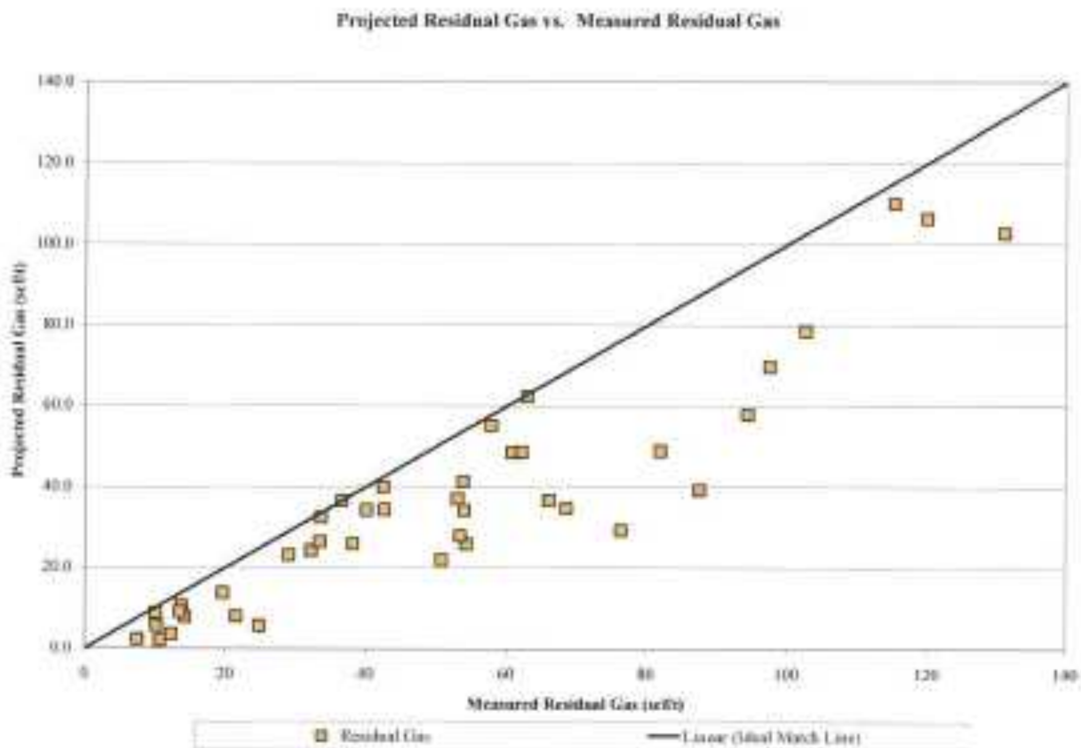
Figure 5. Deuterium and C13 Isotopes of Methane.



Measured Residual Gas

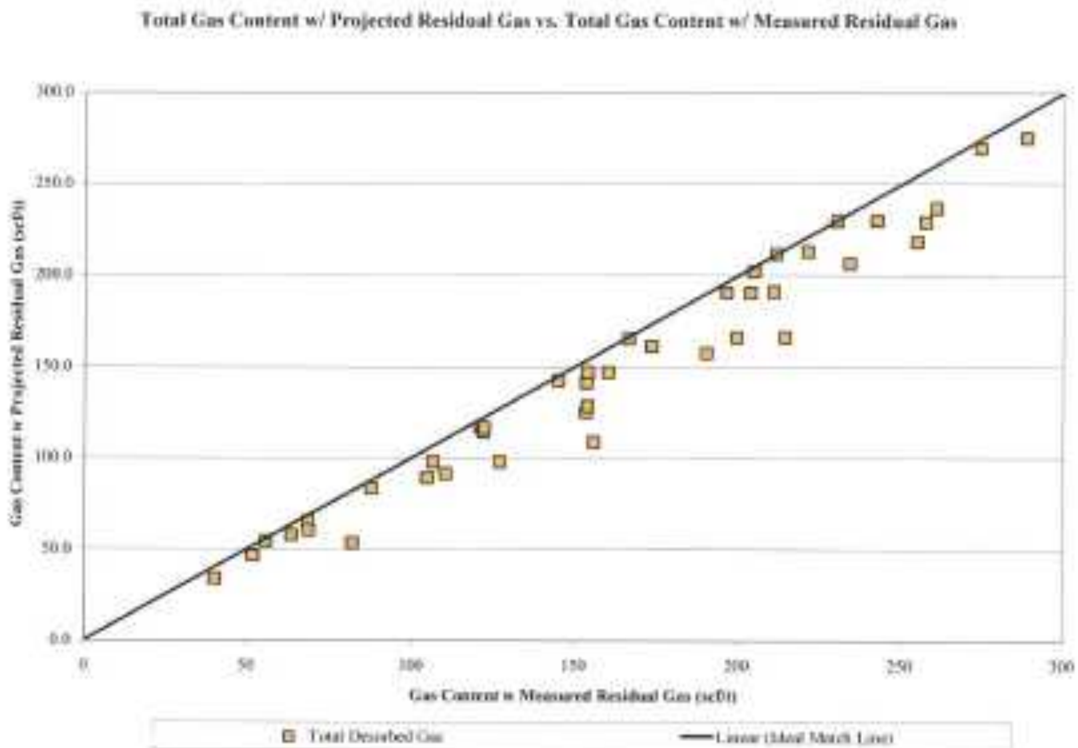
Crushed residual gas was measured on forty-one of the forty-eight desorption samples. Figure 6 shows the measured residual gas versus the projected residual gas on the forty-one samples analyzed. The data from the residual gas analyses can be found in the Excel spreadsheet "Evergreen Resources Alaska Desorption Summary.xls."

Figure 6. Projected Residual Gas vs. Measured Residual Gas



Measured residual gas typically exceeds the mathematically derived projected residual gas. However when total gas content using projected residual gas is compared with total gas content using measured residual gas, the differences becomes less significant (Figure 7).

Figure 7. Total Gas Content with Projected Residual Gas vs. Total Gas Content with Measured Residual Gas



Mathematically projected residual gas is best used for estimating total sorbed gas before desorption is complete. Near the end of desorption when the desorption curve flattens, the projections of residual gas underestimate the total gas remaining in the samples. This happens because a certain amount of gas is always retained in a coal at atmospheric pressure when the sample is in equilibrium with a 100% atmosphere of that gas (i.e., residual gas by definition). When this equilibrium is reached inside a desorption canister, the curve flattens to zero slope and becomes useless for mathematically estimating true residual gas. Typically when this happens, residual gas amounts to less than 10% of total gas, so the differences between projected residual gas and crushed measured residual gas become trivial.

Adsorption Isotherms

Evergreen Resources chose eight coal samples from the Alaska project core holes for methane adsorption isotherm analysis. Dr. Marc Bustin performed these analyses in his coal laboratory at University of British Columbia, Vancouver, B.C.

In the samples that were chosen for methane adsorption isotherms, the data suggests that the coals are all over-saturated with gas at the calculated reservoir pressures and temperatures. These calculated pressures were derived using an estimated pressure gradient provided by the client of 0.43 psi/ft (Figure 8 and Table 5). The reservoir temperatures were calculated using the rather sparse bottom-hole temperature available in the area. These isotherms were run only on methane, but that should not give rise to apparent over-saturation, since all the sorbed gases exceeded 99% methane (except for the Little Su well). The most likely reason for the apparent over-saturation of the coals is that the isotherms were run at too high a temperature (i.e., reservoir temperature was lower than estimated). Measured gas contents calculated on a dry ash-free basis appear even a poorer match to the sorptive capacities, but that may be due to unreliability of calculated dry ash-free gas contents for high ash-content coals and carbonaceous shales.

Figure 8. Total Desorbed Gas Content vs. Methane Sorptive Capacity

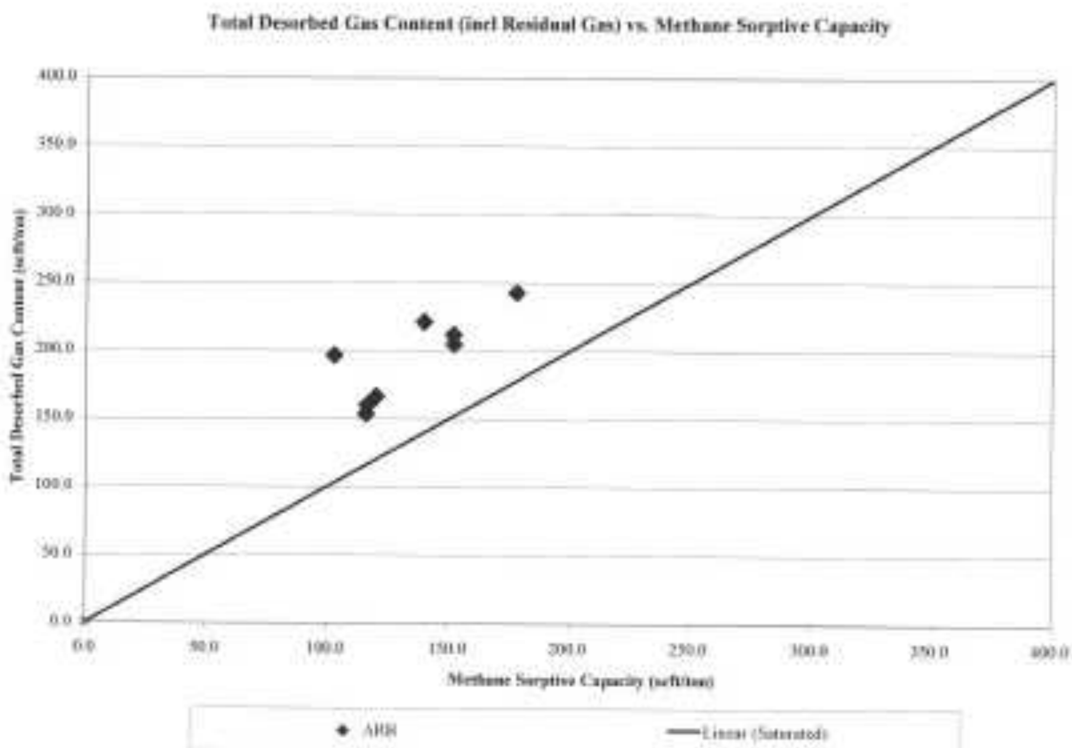


Table 5. Total Desorbed Gas and Methane Sorptive Capacity

Canister #	Zone	Well Name	Driller's Depth (top) (ft)	Reservoir Pressure (psi)	Total Gas Content As-received Basis Lost + Measured + Measured Residual Gas (scft/ton)	Methane Sorptive Capacity As-received Basis @Reservoir Pressure (scft/ton)	Lithology
EHP-09	Tyonek	Houston Pit #1	1112	478.7	166.4	120.1	Coal
EHP-11	Tyonek	Houston Pit #1	1276	548.9	134.0	116.0	Coal
ELS-03	Chickaloon	Little Su #1	2000	860.3	160.3	116.6	Carb Shale
ES-14	Tyonek	Slats #1	1726	742.6	204.8	152.0	Coal
ES-20	Tyonek	Slats #1	2211	950.9	211.6	151.8	Coal
ES-26	Tyonek	Slats #1	2682	1153.7	196.5	102.7	Carb Shale
ES-27	Tyonek	Slats #1	2758	1186.3	242.5	177.8	Coal
ES-28	Tyonek	Slats #1	2858	1229.4	221.2	139.5	Coal

Bulk Density, Moisture, Ash and Sulfur

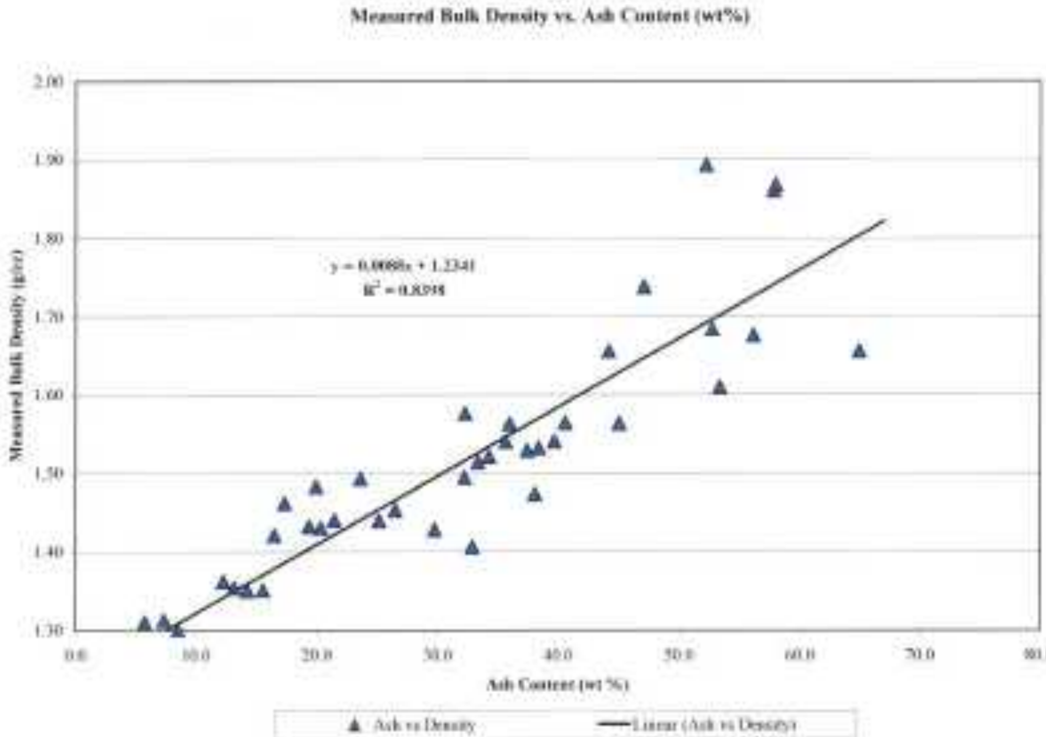
Bulk density was measured and proximate analyses performed on all but two coals which had low gas contents. Full proximates were run on all the isotherm samples and three additional samples. Short proximate analyses were run on all but one of the other coal samples taken (see Table 6, "Evergreen-Alaska-Proximates.xls", and "Evergreen Resources Alaska Desorption Summary.xls"). Ash content of the coals was variable, averaging 25.9%. Ash content of coals ranged from 6.5 % ash to 47.1%. Rocks with greater than 50% ash are considered carbonaceous shales. Carbonaceous shales that were canned range had a range of ash contents from 52.2% to 64.9%. Canned samples of the Chickaloon Formation from the Little Su well all fell into the category of carbonaceous shales. Lignites of the Sterling Formation from the Kashwitna Lake and the Sheep Creek wells were the only consistently low ash content "coals", varying between 5.0% and 8.4% ash. Sulfur was uniformly low in all the Alaska coals, averaging 0.20%.

Table 6. Proximate Analyses Data with Averages

Bulk Density Measurements and Proximate Analyses:							
Canister Number	Depth (ft)	Zone	Total Moisture Weight %.	Ash Content As Received %.	Sulfur Content Weight %.	Measured Bulk Density (g/cc)	Lithology
EHP-01	293.0	Tyonek	28.3	19.9	0.13	1.48	Coal
EHP-03	582.7	Tyonek	13.3	45.0	0.17	1.56	Coal
EHP-04	602.5	Tyonek	13.9	44.2	0.14	1.66	Coal
EHP-05	827.0	Tyonek	11.9	32.2	0.28	1.49	Coal
EHP-06	838.0	Tyonek	12.1	10.7	0.18	1.29	Coal
EHP-07	937.0	Tyonek	13.0	47.1	0.08	1.74	Coal
EHP-08	1104.2	Tyonek	11.8	16.5	0.11	1.42	Coal
EHP-09	1112.3	Tyonek	9.2	29.7	0.20	1.43	Coal
EHP-10	1157.6	Tyonek	13.4	32.8	0.30	1.41	Coal
EHP-11	1275.5	Tyonek	11.2	39.7	0.21	1.54	Coal
ELS-01	322.0	Tyonek	7.3	35.9	0.34	1.56	Coal
ES-01	500.4	Tyonek				1.46	Coal
ES-02	578.0	Tyonek				1.28	Coal
ES-03	733.7	Tyonek	13.8	38.0	0.18	1.47	Coal
ES-04	779.8	Tyonek	13.8	6.5	0.25	1.25	Coal
ES-05	841.4	Tyonek	13.6	14.3	0.35	1.35	Coal
ES-07	1091.0	Tyonek	10.7	33.3	0.11	1.51	Coal
ES-08	1165.6	Tyonek	13.5	15.5	0.14	1.35	Coal
ES-09	1237.7	Tyonek	10.8	23.6	0.16	1.49	Coal
ES-10	1322.0	Tyonek	10.3	40.6	0.12	1.56	Coal
ES-11	1408.9	Tyonek	13.1	19.3	0.28	1.41	Coal
ES-12	1471.2	Tyonek	12.2	13.2	0.32	1.35	Coal
ES-13	1700.1	Tyonek	10.6	35.6	0.33	1.54	Coal
ES-14	1726.0	Tyonek	11.3	25.1	0.16	1.44	Coal
ES-15	1801.5	Tyonek	10.2	26.4	0.16	1.45	Coal
ES-16	1951.0	Tyonek	11.4	7.3	0.16	1.31	Coal
ES-17	2004.0	Tyonek	9.9	32.2	0.17	1.58	Coal
ES-18	2055.1	Tyonek	8.9	20.3	0.26	1.43	Coal
ES-19	2113.0	Tyonek	11.1	8.5	0.24	1.30	Coal
ES-20	2210.5	Tyonek	9.1	34.2	0.18	1.52	Coal
ES-22	2302.0	Tyonek	9.8	12.3	0.32	1.36	Coal
ES-23	2429.0	Tyonek	9.0	17.3	0.15	1.46	Coal
ES-25	2624.0	Tyonek	8.9	5.7	0.17	1.31	Coal
ES-27	2757.9	Tyonek	9.4	21.4	0.19	1.44	Coal
ES-28	2858.0	Tyonek	9.0	37.4	0.11	1.53	Coal
ES-29	2901.3	Tyonek	7.7	38.3	0.24	1.53	Coal
		Coal Averages:	**11.6**	**25.9**	**0.20**	**1.45**	
ELS-02	1970.0	Chickaloon	15.2	57.8	0.16	1.86	Carb Shale
ELS-03	2000.0	Chickaloon	5.1	64.9	0.13	1.66	Carb Shale
ELS-04	2038.5	Chickaloon	10.9	52.7	0.13	1.68	Carb Shale
ES-06	965.0	Tyonek	12.2	56.1	0.15	1.68	Carb Shale
ES-21	2283.0	Tyonek	9.1	52.2	0.26	1.89	Carb Shale
ES-24	2529.3	Tyonek	7.8	57.9	0.10	1.87	Carb Shale
ES-26	2682.0	Tyonek	7.4	53.3	0.12	1.61	Carb Shale
		Carb Shale Averages:	**9.7**	**56.4**	**0.15**	**1.75**	
EKL-01	1021.0	Sterling	17.8	8.4	0.11	1.25	Lignite
ESC-01	1018.0	Sterling	32.4	5.0	0.12	1.30	Lignite
ESC-02	1121.0	Sterling	32.1	6.0	0.18	1.28	Lignite
ESC-03	1199.0	Sterling				1.42	Lignite
		Lignite Averages:	**27.4**	**6.5**	**0.14**	**1.31**	

Bulk density of a coal is typically a function of ash content. Figure 9 shows the relationship between measured bulk density and ash content in these Alaska coals and carbonaceous shales.

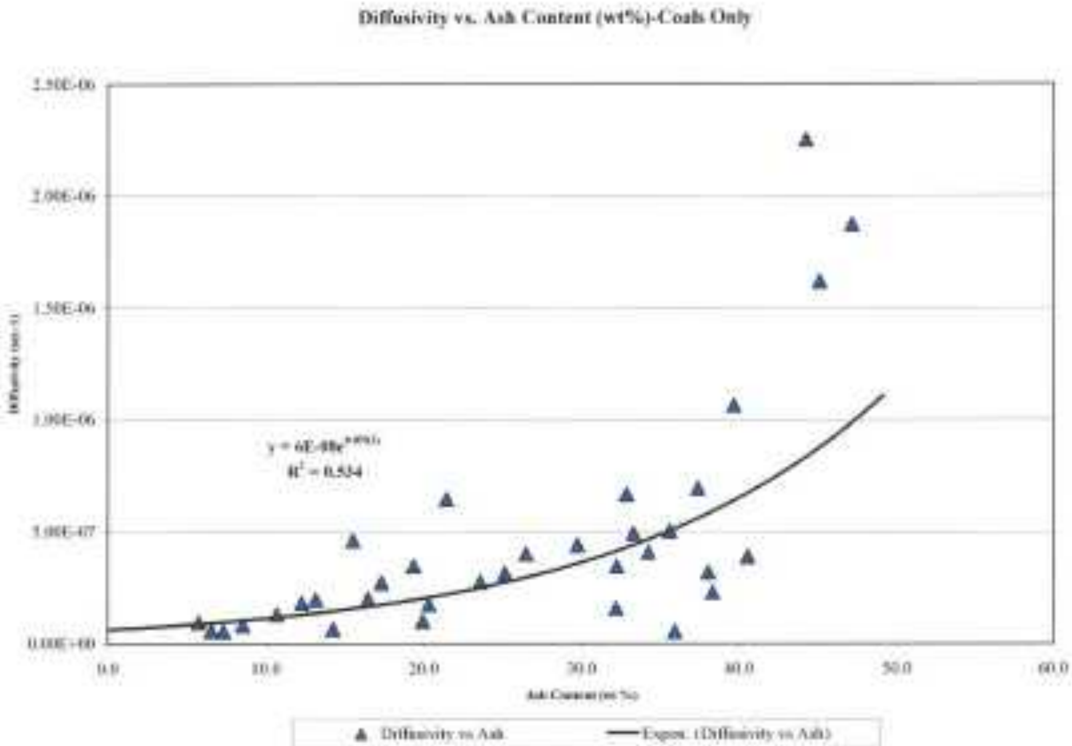
Figure 9. Measured Bulk Density vs. Ash Content



Coal Diffusivity

Diffusivity of coals was calculated using a formula provided by Dr. John Seidel, petroleum reservoir engineer. Plots were made to examine the relationship of diffusivity with ash content, depth, and gas content. Of the three parameters examined, diffusivity shows the best correlation with ash content of the coals (Figure 10). Diffusivity shows an increase with increasing ash content in the Alaska coals and increases markedly when the threshold is approached to carbonaceous shales.

Figure 10. Coal Diffusivity vs. Ash Content



When plotted against depth for all the samples, diffusivity showed a slight tendency to decrease with depth, but when restricted to less shaley coals (<40% Ash), no relationship was apparent (Figure 11). These shalier samples were excluded from the plot shown in Figure 11 because of the overriding effect of high ash content upon diffusivity. Likewise, when diffusivity is plotted against gas content, using only the less shaley coals, no relationship is apparent (Figure 12).

Figure 11. Diffusivity vs. Depth (for coals with <40% Ash)

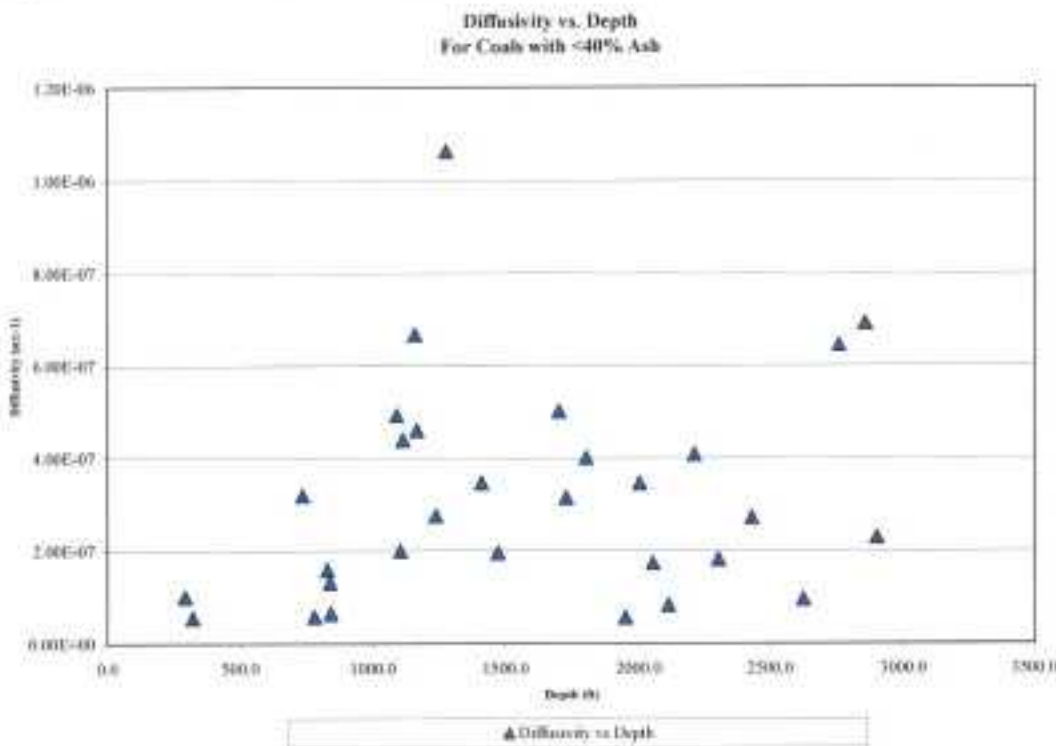
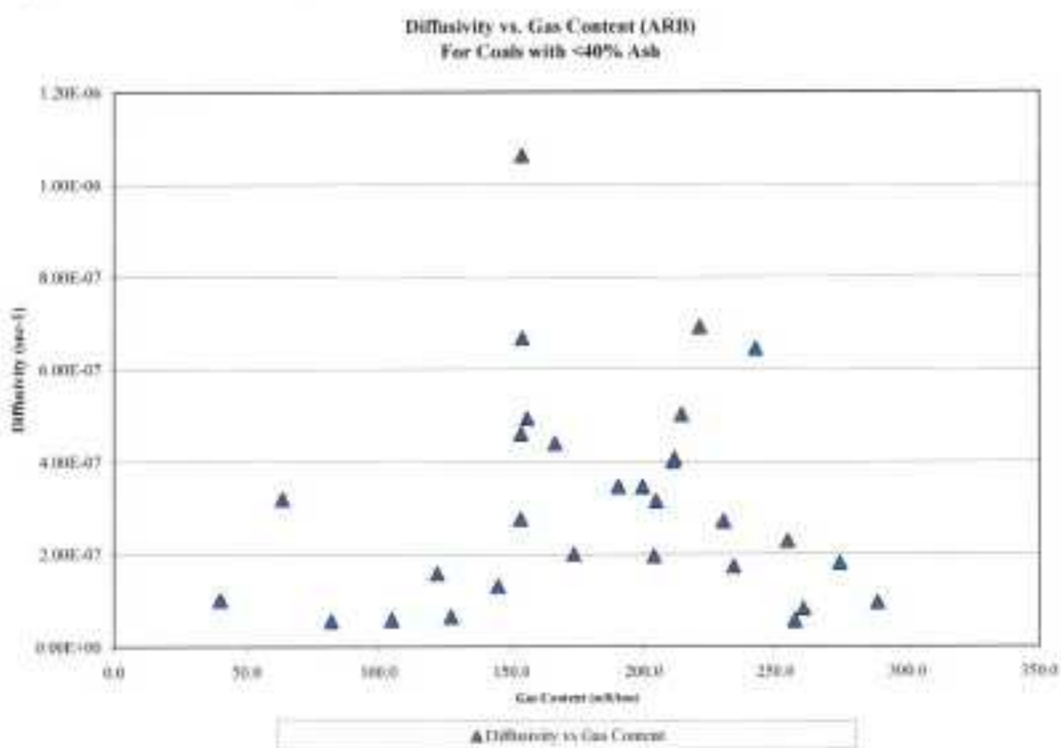


Figure 12. Diffusivity vs. Gas Content (for coals with <40% Ash)



Other Coal Analyses

In addition to the eight adsorption isotherms, Marc Bustin analyzed the same eight samples for vitrinite reflectance, maceral composition, macroscopic coal descriptions, and macroscopic cleat mineralization descriptions. Only one sample (ES-27) contained sufficient cleat minerals for X-ray diffraction analysis, and that mineralization was entirely calcite. Bustin's data is also summarized in a separate report given to Pioneer Natural Resources, Inc.

Vitrinite and Maceral Analysis

According to Marc Bustin, the coals analyzed from the Alaska project varied between lignites and high volatile bituminous B (see Table 7 below).

Table 7. Vitrinite and Coal Rank (from Bustin):

Canister	Zone	Well Name	Vitrinite Refl%		Coal
			Mean Ro. %	St. Dev	Rank
EHP-09	Tyonek	Houston Pit#1	0.45	0.05	SBA
EHP-11	Tyonek	Houston Pit#1	0.46	0.04	SBA
ELS-03	Tyonek	Little Su#1	0.67	0.08	HVB
ES-14	Tyonek	Slats#1	0.49	0.03	SBA
ES-20	Tyonek	Slats#1	0.46	0.04	SBA
ES-26	Tyonek	Slats#1	0.46	0.03	SBA
ES-27	Tyonek	Slats#1	0.51	0.05	SBA/HVC
ES-28	Tyonek	Slats#1	0.50	0.05	SBA/HVC
EKL-01	Sterling	Kaswitna Lake#1	0.24	0.05	Lignite
ESC-01	Sterling	Sheep Creek#1	0.20	0.01	Lignite
ESC-02	Sterling	Sheep Creek#1	0.20	0.05	Lignite

SBA- sub bituminous A
HVB- high volatile bituminous B
HVC- high volatile bituminous C

Table 8 shows the maceral composition of the coals. The coals analyzed were composed predominantly of vitrinite, with small amounts of inertinite, trace amounts of liptinite and pyrite. The lignites shown separately are predominantly huminite with traces of inertinite and liptinite.

Table 8. Maceral Analysis (from Bustin):

Canister	Zone	Well Name	Vitrinite		Inertinite		Liptinite			
			Collo-telinite	Collo-detrinite	Semi-fusinite	Fusinite	cuti-nite	resinite	sub-erinite	sporinite
EHP-09	Tyonek	Houston Pit#1	36	63	trace	trace	trace	trace	trace	1
EHP-11*	Tyonek	Houston Pit#1	24	69	3	1	trace			3
ELS-03*	Tyonek	Little Su#1	20	75	3	trace	trace			1
ES-14*	Tyonek	Slats#1	43	56	trace	trace	trace			1
ES-20	Tyonek	Slats#1	47	53	trace	trace	trace			1
ES-26*	Tyonek	Slats#1	50	50	trace					trace
ES-27*	Tyonek	Slats#1	38	61	1	trace	trace			trace
ES-28*	Tyonek	Slats#1	49	51	trace	trace				trace

* carbargilite

Sample	Huminite		Inertinite		Liptinite				Pyrite
	Textinite	Detrinite	Semi-fusinite	Fusinite	cuti-nite	resinite	sub-erinite	sporinite	
EKL-01	95	5	trace	trace				trace	trace
ESC-01	95	5	trace	trace				trace	
ESC-02	54	46	trace	trace				trace	

Macroscopic coal descriptions and Cleat Mineralogy

Macroscopic coal descriptions and cleat mineralogy (x-ray diffraction) can be found in the report by Marc Bustin, which has been provided to the client, as well as being included with the final desorption report data CD: Core photos accompany descriptions in Bustin's report and are contained in the desorption report CD.

Conclusions

On an as-received basis, the total gas content for the Alaska project coals varies between 0.0 and 288.7 scft/ton. The highest gas contents are observed in the Slats well (averaging 188 scft/ton total gas). At equivalent depths, coals from the Slats well and the Houston Pit well had similar gas contents, but the Houston Pit well was not drilled as deep as the Slats well. Coals from the Kashwitna Lake and Sheep Creek wells had the lowest gas contents. All coals canned averaged 171.0 scft/ton on an as-received basis, and 269.7 scft/ton on a dry ash-free basis. Ash content of the coals was variable, averaging 25.9%. Ash content of coals ranged from 6.5 % ash to 47.1%. Rocks with greater than 50% ash are considered carbonaceous shales. Carbonaceous shales that were canned had a range of ash contents from 52.2% to 64.9%.

Lost gas estimates in the coals averaged 10% of the total gas. The average time for lost gas was 18 minutes. Residual/remaining gas averaged 28% of total gas, which is a higher percentage of residual gas than is present in most coals. The coals in this area had low reservoir temperatures, in part related to very low mean annual surface temperatures. Since sorptive capacity of a coal increases with decreasing reservoir temperature, the low reservoir temperatures in this area would allow the coals to retain a higher percentage of residual gas at atmospheric pressure. Consequently these coals would be expected to retain a higher percentage of gas that could not be produced at existing reservoir temperatures.

Vitrinite reflectance measurements show the coals from the Kashwitna Lake and Sheep Creek wells are lignites, which typically contain little gas. The Little Su well, on the other hand has coals of much higher rank: hi-volatile bituminous B with a vitrinite reflectance of 0.67%. Coals of this rank are capable of generating thermal gas, but since the gas contents of coals from the Little Su were low for their depths, some geologic factor has influenced the gas content of these coals. In the Houston Pit and Slats wells, coal rank shows only a slight increase over the last 1700 feet of depth. This may explain why the coals seem to show a relatively small increase in gas content beyond 1700 feet for these two.

Gases from the Houston Pit and Slats wells are all over 99% methane with only traces of C2 and heavier gases. The one gas sample taken from the Little Su well was a wet gas with over 10% C2 and 2%C3. Isotopic analysis of deuterium and C_{13} shows five of the gas samples had a near-surface biogenic gas origin, an interpretation reinforced by gas sample compositions of nearly pure methane from the same wells (Houston Pit and Slats). The sample from the Little Su well had an isotopic composition in the range of thermogenic gas, an interpretation reinforced by the wet gas composition of this sample.

In the samples that were chosen for methane adsorption isotherms, the data suggests that the coals are all over-saturated with gas at the calculated reservoir pressures and temperatures. These isotherms were run only on methane, but that should not give rise to apparent over-saturation, since all the sorbed gases exceeded 99% methane, except for the Little Su well. The most likely reason for the apparent over-saturation of the coals is that the isotherms were run at too high a temperature (i.e., reservoir temperature was lower than estimated).

Diffusivity was compared with ash content, depth, and gas content. Of the three parameters examined, diffusivity showed a relationship only with ash content of the coals. Diffusivity increases with increasing ash content in the Alaska coals, and does so markedly when the threshold is approached to carbonaceous shales.

Enclosures (in print and/or on CD)

- Coal Desorption Report (Evergreen Coal Desorption Report.doc).
- Coal Desorption Summary (Evergreen Resources Alaska Desorption Summary.xls).
- Individual Canister Desorption Reports and core photos (Excel spreadsheets and Plots-printed in report and on CD).
- Gas Analysis data and plots (Evergreen Alaska Gas Analyses.xls and Evergreen Alaska Isotope Plots.pdf – on CD).
- Proximate Analysis data (Evergreen-Alaska-Proximates.xls on CD)
- Other Coal Analyses: Adsorption Isotherm Analyses, Vitrinite reflectance, Maceral composition, Macroscopic coal descriptions, and Cleat mineralization (Provided on a separate report furnished by RMB Earth Science Consultants Ltd., Excel spreadsheets to be included on data CD).
- Geologic Wellsite Reports
- Geologic Strip Logs for Individual Wells

Appendix G
ASRC CONSULTING AND ENVIRONMENTAL SERVICES
Drilling Cost Estimate
for 2027 Appraisal Program

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Cost Cat 1	Ln #	Invoice Description	AFE Cost	Field Cost	Actual Cost
Drilling	1	**Conductor/Drive**	$ 11,393	$ 1,139	$ 12,533
Drilling	2	**Surface Casing**	$ 230,000	$ 23,000	$ 253,000
Drilling	3	**Intermediate Casing**	$ 303,600	$ 30,360	$ 333,960
Drilling	4	**Production Casing**	$ 341,550	$ 34,155	$ 375,705
Drilling	5	**Liner**	$ -	$ -	$ -
Completion	6	**Tubing**	$ 94,875	$ 9,488	$ 104,363
Drilling	7	**Casing Equipment & Accessories**	$ 179,055	$ 17,906	$ 196,961
Drilling	8	**Wellhead & Tree**	$ 454,250	$ 45,425	$ 499,675
Drilling	9	**Surface Completion Equipment**	$ -	$ -	$ -
Completion	10	**Downhole Completion Equipment**	$ 57,500	$ 5,750	$ 63,250
Completion	11	**Downhole Artificial Lift Equipment**	$ 920,000	$ 92,000	$ 1,012,000
Completion	12	**Miscellaneous Equipment**	$ 86,250	$ 8,625	$ 94,875
Drilling	13	**Buildings, Cellars, & Structures**	$ 143,750	$ 14,375	$ 158,125
MOB/DMOB	14	**Site Work, Surveying, Construction, & Positioning**	$ 230,000	$ 23,000	$ 253,000
Drilling	15	**Conductor & Cellar Setting Operations**	$ 34,500	$ 3,450	$ 37,950
Drilling	16	**Power/Fuel**	$ 1,364,763	$ 136,476	$ 1,501,239
Drilling	17	**Housing, Camps, Water, & Catering**	$ 1,131,600	$ 113,160	$ 1,244,760
Drilling	18	**Trash Disposal**	$ 26,048	$ 2,605	$ 28,652
Drilling	19	**Information/Communication**	$ 11,615	$ 1,162	$ 12,777
Drilling	20	**Insurance**	$ 116,150	$ 11,615	$ 127,765
Drilling	21	**Misc Supplies, Consumables, & Equipment**	$ 116,150	$ 11,615	$ 127,765
Drilling	22	**Pre/Post Rig Work & Other Well Preparation**	$ -	$ -	$ -
MOB/DMOB	23	**Rig Mobilization / Demobilization**	$ 2,208,000	$ 220,800	$ 2,428,800
Drilling	24	**Rig / Drilling Contractor - Day Rate**	$ 2,461,000	$ 246,100	$ 2,707,100
Drilling	25	**Rig Support Services**	$ 551,713	$ 55,171	$ 606,884
Drilling	26	**Equipment Rental - Downhole**	$ 275,138	$ 27,514	$ 302,651
Drilling	27	**Equipment Rental - Surface**	$ 1,308,585	$ 130,859	$ 1,439,444
Drilling	28	**Bits**	$ 270,250	$ 27,025	$ 297,275
Drilling	29	**Mud Processing Equipment & Service**	$ -	$ -	$ -
Drilling	30	**Drilling Fluids, Materials, & Services**	$ 1,303,525	$ 130,353	$ 1,433,878
Completion	31	**Completion Fluids & Other Chemicals**	$ 150,650	$ 15,065	$ 165,715
Drilling	32	**Directional Drilling Equipment & Services**	$ 509,881	$ 50,988	$ 560,869
Logging	33	**MWD / LWD Equipment & Services**	$ 1,591,140	$ 159,114	$ 1,750,254
Drilling	34	**Downhole Surveying & Processing**	$ -	$ -	$ -
Logging	35	**Mud Logging Services**	$ 529,000	$ 52,900	$ 581,900
Completion	36	**Casing Crews, Pipe Handling Equipment, & Services**	$ 288,650	$ 28,865	$ 317,515
Drilling	37	**Cementing Materials & Services**	$ 1,207,500	$ 120,750	$ 1,328,250
Drilling	38	**Wellhead / XMAS Tree Services**	$ 267,950	$ 26,795	$ 294,745
Completion	39	**Down Hole Completion Materials & Services**	$ 115,000	$ 11,500	$ 126,500
Drilling	40	**Cuttings & Transport Disposal**	$ 1,281,675	$ 128,168	$ 1,409,843
Drilling	41	**Transportation - Trucking**	$ 1,793,138	$ 179,314	$ 1,972,451
Drilling	42	**Transportation - Barge / Boat**	$ -	$ -	$ -
Drilling	43	**Transportation - Airplane / Helicopter**	$ 925,750	$ 92,575	$ 1,018,325
Drilling	44	**Freight & Shipping**	$ 58,075	$ 5,808	$ 63,883
Logging	45	**Electric Line Services**	$ 1,667,500	$ 166,750	$ 1,834,250
Drilling	46	**Wireline / Slickline Services**	$ 57,500	$ 5,750	$ 63,250
Completion	47	**Perforating Services**	$ 172,500	$ 17,250	$ 189,750
Drilling	48	**Fishing / Milling Services**	$ -	$ -	$ -
Completion	49	**Frac Equipment & Services**	$ -	$ -	$ -
Completion	50	**Coiled Tubing Service**	$ 776,250	$ 77,625	$ 853,875
Drilling	51	**Repairs, Testing, Certification & Inspection**	$ 172,500	$ 17,250	$ 189,750
Coring	52	**Coring Services**	$ 828,000	$ 82,800	$ 910,800
Logging	53	**Geology Data & Analysis**	$ 69,000	$ 6,900	$ 75,900
Production	54	**Production Testing & Well Stimulation**	$ -	$ -	$ -
Production	55	**Well Abandonment Equipment & Services**	$ -	$ -	$ -
Drilling	56	**HSE Equipment & Services**	$ 187,163	$ 18,716	$ 205,879
Well Coord	57	**Wellsite Contract Labor**	$ 793,500	$ -	$ 793,500
ACES	58	**Engineering Services - Office Based**	$ 1,058,719		$ 1,058,719
ACES	59	**Overhead & Allocated Costs**	$ 700,513	$ -	$ 700,513

Assumptions:
- includes 4 days of RU time
- Assumes drilling rig rates (not a water well rig)
- assumes 9000' MD/TVD TD for well
- 43 days for drilling/completion
- includes LIH insurance for Drlg BHAs for project
- includes 5 total days for coring
- includes 3 total days for open hole logging
- assumes ESP/Access ESP type completion
- includes CT lift
- includes 14 days of Rig down & demob costs for all equipment
- assumes camp stays at initial rig up location
- includes fixed wing dedicated support for emergency response, personnel from Anchorage, etc. Reduces truck quantity requirements as well
- includes disposal of fluids/cuttings in Kenai

- excludes all costs associated with production
- excludes produced water disposal costs
- excludes road and pad costs

Cost Cat 1	Ln #	Invoice Description	AFE Cost	Field Cost	Actual Cost
Drilling	1	**Conductor/Drive**	$ 11,393	$ 1,139	$ 12,533
Drilling	2	**Surface Casing**	$ 230,000	$ 23,000	$ 253,000
Drilling	3	**Intermediate Casing**	$ 441,600	$ 44,160	$ 485,760
Drilling	4	**Production Casing**	$ 550,275	$ 55,028	$ 605,303
Drilling	5	**Liner**	$ 139,150	$ 13,915	$ 153,065
Completion	6	**Tubing**	$ 170,775	$ 17,078	$ 187,853
Drilling	7	**Casing Equipment & Accessories**	$ 244,893	$ 24,489	$ 269,382
Drilling	8	**Wellhead & Tree**	$ 454,250	$ 45,425	$ 499,675
Drilling	9	**Surface Completion Equipment**	$ -	$ -	$ -
Completion	10	**Downhole Completion Equipment**	$ 57,500	$ 5,750	$ 63,250
Completion	11	**Downhole Artificial Lift Equipment**	$ 115,000	$ 11,500	$ 126,500
Completion	12	**Miscellaneous Equipment**	$ 86,250	$ 8,625	$ 94,875
Drilling	13	**Buildings, Cellars, & Structures**	$ 143,750	$ 14,375	$ 158,125
MOB/DMOB	14	**Site Work, Surveying, Construction, & Positioning**	$ -	$ -	$ -
Drilling	15	**Conductor & Cellar Setting Operations**	$ 34,500	$ 3,450	$ 37,950
Drilling	16	**Power/Fuel**	$ 1,467,400	$ 146,740	$ 1,614,140
Drilling	17	**Housing, Camps, Water, & Catering**	$ 1,286,850	$ 128,685	$ 1,415,535
Drilling	18	**Trash Disposal**	$ 27,888	$ 2,789	$ 30,676
Drilling	19	**Information/Communication**	$ 13,340	$ 1,334	$ 14,674
Drilling	20	**Insurance**	$ 133,400	$ 13,340	$ 146,740
Drilling	21	**Misc Supplies, Consumables, & Equipment**	$ 76,705	$ 7,671	$ 84,376
Drilling	22	**Pre/Post Rig Work & Other Well Preparation**	$ -	$ -	$ -
MOB/DMOB	23	**Rig Mobilization / Demobilization**	$ 483,000	$ 48,300	$ 531,300
Drilling	24	**Rig / Drilling Contractor - Day Rate**	$ 2,806,000	$ 280,600	$ 3,086,600
Drilling	25	**Rig Support Services**	$ 633,650	$ 63,365	$ 697,015
Drilling	26	**Equipment Rental - Downhole**	$ 341,550	$ 34,155	$ 375,705
Drilling	27	**Equipment Rental - Surface**	$ 1,460,730	$ 146,073	$ 1,606,803
Drilling	28	**Bits**	$ 270,250	$ 27,025	$ 297,275
Drilling	29	**Mud Processing Equipment & Service**	$ -	$ -	$ -
Drilling	30	**Drilling Fluids, Materials, & Services**	$ 1,935,450	$ 193,545	$ 2,128,995
Completion	31	**Completion Fluids & Other Chemicals**	$ 150,650	$ 15,065	$ 165,715
Drilling	32	**Directional Drilling Equipment & Services**	$ 589,318	$ 58,932	$ 648,249
Logging	33	**MWD / LWD Equipment & Services**	$ 1,725,460	$ 172,546	$ 1,898,006
Drilling	34	**Downhole Surveying & Processing**	$ -	$ -	$ -
Logging	35	**Mud Logging Services**	$ 649,750	$ 64,975	$ 714,725
Completion	36	**Casing Crews, Pipe Handling Equipment, & Services**	$ 312,800	$ 31,280	$ 344,080
Completion	37	**Cementing Materials & Services**	$ 977,500	$ 97,750	$ 1,075,250
Completion	38	**Wellhead / XMAS Tree Services**	$ 284,050	$ 28,405	$ 312,455
Completion	39	**Down Hole Completion Materials & Services**	$ 115,000	$ 11,500	$ 126,500
Drilling	40	**Cuttings & Transport Disposal**	$ 1,261,550	$ 126,155	$ 1,387,705
Drilling	41	**Transportation - Trucking**	$ 1,157,475	$ 115,748	$ 1,273,223
Drilling	42	**Transportation - Barge / Boat**	$ -	$ -	$ -
Drilling	43	**Transportation - Airplane / Helicopter**	$ 982,100	$ 98,210	$ 1,080,310
Drilling	44	**Freight & Shipping**	$ 66,700	$ 6,670	$ 73,370
Logging	45	**Electric Line Services**	$ 1,667,500	$ 166,750	$ 1,834,250
Drilling	46	**Wireline / Slickline Services**	$ 57,500	$ 5,750	$ 63,250
Completion	47	**Perforating Services**	$ 172,500	$ 17,250	$ 189,750
Drilling	48	**Fishing / Milling Services**	$ -	$ -	$ -
Completion	49	**Frac Equipment & Services**	$ -	$ -	$ -
Completion	50	**Coiled Tubing Service**	$ 776,250	$ 77,625	$ 853,875
Drilling	51	**Repairs, Testing, Certification & Inspection**	$ -	$ -	$ -
Coring	52	**Coring Services**	$ 1,288,000	$ 128,800	$ 1,416,800
Logging	53	**Geology Data & Analysis**	$ 69,000	$ 6,900	$ 75,900
Production	54	**Production Testing & Well Stimulation**	$ -	$ -	$ -
Production	55	**Well Abandonment Equipment & Services**	$ -	$ -	$ -
Drilling	56	**HSE Equipment & Services**	$ 224,250	$ 22,425	$ 246,675
Well Coord	57	**Wellsite Contract Labor**	$ 809,600	$ -	$ 809,600
ACES	58	**Engineering Services - Office Based**	$ 523,825		$ 523,825
ACES	59	**Overhead & Allocated Costs**	$ 252,390	$ -	$ 252,390

Assumptions:
- includes 4 days of RU time
- Assumes drilling rig rates (not a water well rig)
- assumes ~14500' MD / 10500' TVD TD for well to allow kickout to west side of fault
- 54 days for drilling/completion
- includes 5 total days for coring
- includes 3 total days for open hole logging
- includes contingency costs for 4-1/2" liner and small OD coring tools but does NOT include needed rig time
- assumes PCP type completion
- includes CT lift
- includes 3 days for Rig down
- includes fixed wing dedicated support for emergency response, personnel from Anchorage, etc. Reduces truck quantity requirements as well
- assumes camp stays at initial rig up location
- includes disposal of fluids/cuttings in Kenai

- excludes road and pad costs
- excludes all costs associated with production
- excludes produced water disposal costs
- excludes all major mob and demob costs

Cost Cat 1	Ln #	Invoice Description	AFE Cost	Field Cost	Actual Cost
Drilling	1	**Conductor/Drive**	$ 11,393	$ 1,139	$ 12,533
Drilling	2	**Surface Casing**	$ 253,000	$ 25,300	$ 278,300
Drilling	3	**Intermediate Casing**	$ 303,600	$ 30,360	$ 333,960
Drilling	4	**Production Casing**	$ 246,675	$ 24,668	$ 271,343
Drilling	5	**Liner**	$ -	$ -	$ -
Completion	6	**Tubing**	$ 82,225	$ 8,223	$ 90,448
Drilling	7	**Casing Equipment & Accessories**	$ 188,614	$ 18,861	$ 207,476
Drilling	8	**Wellhead & Tree**	$ 454,250	$ 45,425	$ 499,675
Drilling	9	**Surface Completion Equipment**	$ -	$ -	$ -
Completion	10	**Downhole Completion Equipment**	$ 57,500	$ 5,750	$ 63,250
Completion	11	**Downhole Artificial Lift Equipment**	$ 115,000	$ 11,500	$ 126,500
Completion	12	**Miscellaneous Equipment**	$ 86,250	$ 8,625	$ 94,875
Drilling	13	**Buildings, Cellars, & Structures**	$ 143,750	$ 14,375	$ 158,125
MOB/DMOB	14	**Site Work, Surveying, Construction, & Positioning**	$ -	$ -	$ -
Drilling	15	**Conductor & Cellar Setting Operations**	$ 34,500	$ 3,450	$ 37,950
Drilling	16	**Power/Fuel**	$ 1,555,375	$ 155,538	$ 1,710,913
Drilling	17	**Housing, Camps, Water, & Catering**	$ 1,323,075	$ 132,308	$ 1,455,383
Drilling	18	**Trash Disposal**	$ 27,485	$ 2,749	$ 30,234
Drilling	19	**Information/Communication**	$ 13,743	$ 1,374	$ 15,117
Drilling	20	**Insurance**	$ 169,625	$ 16,963	$ 186,588
Drilling	21	**Misc Supplies, Consumables, & Equipment**	$ 61,827	$ 6,183	$ 68,010
Drilling	22	**Pre/Post Rig Work & Other Well Preparation**	$ -	$ -	$ -
MOB/DMOB	23	**Rig Mobilization / Demobilization**	$ 1,009,125	$ 100,913	$ 1,110,038
Drilling	24	**Rig / Drilling Contractor - Day Rate**	$ 2,150,500	$ 215,050	$ 2,365,550
Drilling	25	**Rig Support Services**	$ 526,269	$ 52,627	$ 578,896
Drilling	26	**Equipment Rental - Downhole**	$ 466,469	$ 46,647	$ 513,116
Drilling	27	**Equipment Rental - Surface**	$ 1,386,268	$ 138,627	$ 1,524,894
Drilling	28	**Bits**	$ 212,750	$ 21,275	$ 234,025
Drilling	29	**Mud Processing Equipment & Service**	$ -	$ -	$ -
Drilling	30	**Drilling Fluids, Materials, & Services**	$ 1,335,438	$ 133,544	$ 1,468,981
Completion	31	**Completion Fluids & Other Chemicals**	$ 150,650	$ 15,065	$ 165,715
Drilling	32	**Directional Drilling Equipment & Services**	$ 518,693	$ 51,869	$ 570,562
Logging	33	**MWD / LWD Equipment & Services**	$ 726,570	$ 72,657	$ 799,227
Drilling	34	**Downhole Surveying & Processing**	$ -	$ -	$ -
Logging	35	**Mud Logging Services**	$ 595,125	$ 59,513	$ 654,638
Completion	36	**Casing Crews, Pipe Handling Equipment, & Services**	$ 261,625	$ 26,163	$ 287,788
Completion	37	**Cementing Materials & Services**	$ 747,500	$ 74,750	$ 822,250
Completion	38	**Wellhead / XMAS Tree Services**	$ 141,450	$ 14,145	$ 155,595
Completion	39	**Down Hole Completion Materials & Services**	$ 115,000	$ 11,500	$ 126,500
Drilling	40	**Cuttings & Transport Disposal**	$ 832,600	$ 83,260	$ 915,860
Drilling	41	**Transportation - Trucking**	$ 1,835,831	$ 183,583	$ 2,019,414
Drilling	42	**Transportation - Barge / Boat**	$ -	$ -	$ -
Drilling	43	**Transportation - Airplane / Helicopter**	$ 1,187,375	$ 118,738	$ 1,306,113
Drilling	44	**Freight & Shipping**	$ 68,713	$ 6,871	$ 75,584
Logging	45	**Electric Line Services**	$ 1,265,000	$ 126,500	$ 1,391,500
Drilling	46	**Wireline / Slickline Services**	$ 57,500	$ 5,750	$ 63,250
Completion	47	**Perforating Services**	$ 172,500	$ 17,250	$ 189,750
Drilling	48	**Fishing / Milling Services**	$ -	$ -	$ -
Completion	49	**Frac Equipment & Services**	$ -	$ -	$ -
Completion	50	**Coiled Tubing Service**	$ 776,250	$ 77,625	$ 853,875
Drilling	51	**Repairs, Testing, Certification & Inspection**	$ -	$ -	$ -
Coring	52	**Coring Services**	$ 753,250	$ 75,325	$ 828,575
Logging	53	**Geology Data & Analysis**	$ 69,000	$ 6,900	$ 75,900
Production	54	**Production Testing & Well Stimulation**	$ -	$ -	$ -
Production	55	**Well Abandonment Equipment & Services**	$ -	$ -	$ -
Drilling	56	**HSE Equipment & Services**	$ 240,494	$ 24,049	$ 264,543
Well Coord	57	**Wellsite Contract Labor**	$ 953,350	$ -	$ 953,350
ACES	58	**Engineering Services - Office Based**	$ 347,588		$ 347,588
ACES	59	**Overhead & Allocated Costs**	$ 262,855	$ -	$ 262,855

Assumptions:
- includes 12 months project permitting & well planning costs
- includes Mob of all equipment and support (14 days mob / 10 days rig up on well)
- Assumes drilling rig rates (not a water well rig)
- assumes 6500' MD/TVD TD for well
- 45 days for drilling/completion
- includes 5 total days for coring
- includes 3 total days for open hole logging
- assumies PCP type completion
- includes CT lift
- 3 days to rig down
- assumes camp stays at initial rig up location
- includes fixed wing dedicated support for emergency response, personnel from Anchorage, etc. Reduces truck quantity requirements as well
- includes disposal of fluids/cuttings in Kenai

- excludes all costs associated with production
- excludes produced water disposal costs
- excludes road and pad costs

Appendix H
Grant Lake Corporation Road, Pad and Water Disposal proposal

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GRANT LAKE

January 5, 2026

ASRC Energy Services
3900 C. Street, Suite 601
Anchorage, AK 99503

Attn: Shahryar Shirzadi, B.S., M.S.

Subsurface and Wells Development

Re: Denali Petroleum and Gas Company
Natural Gas Exploration Project
2026-2027 Road Construction Proposal

Dear Shawn,

Please find attached Grant Lake Corporation's ROM Budget Proposal and Schedule for Denali Petroleum and Gas Company's natural gas exploration road construction project SW of Trapper Creek, Alaska.

To summarize ASRC's goals and those of Denali Petroleum, a 22-mile ice road will need to be constructed this winter, between Mid-January and the end of February, to move equipment to multiple sites along the proposed road in March before breakup in April. Several sets of excavating equipment and three rock crushers must be in-place for road construction before spring breakup. A key factor that must be adhered to is construction of up to 14 culvert crossings on Oil Well Road between May 1 and June 30, per Alaska Fish and Game and Corp of Engineers regulations. Two additional sets of equipment will be used to dig the water reservoirs you require. Two of the rock crushers will be strategically placed to use pit run rock from these excavations for road construction, reducing gravel costs. The overall plan is to build a second ice road in January-February 2027 to move the drill rig to drill site 1 in March.

Please feel free to contact me should you have any questions or wish to meet.

Very Best Regards,

Paul T. Torgerson, President

Cc: Frank Avezac, President, Denali Petroleum and Gas Company
Charles Conrad, President, CC Enterprises
Ted K. Stinson, Project Development Manager, Grant Lake Corporation
Ann M. Ellis, Resource Manager & Landman, Grant Lake Corporation

Grant Lake Corporation - 5223 E. 24th Avenue #14, Anchorage, AK 99508-3828 – (907) 312-0027

DENALI PETROLEUM & GAS COMPANY
2026 Road Construction Program – Phase 1
ROM Budget (Midpoint)

EXECUTIVE SUMMARY

This document presents a Rough Order of Magnitude (ROM) cost estimate for the 2026 Phase 1 Road Construction Program in support of Denali Petroleum and Gas Company's Susitna Basin gas exploration activities. The ROM identifies the anticipated base installed construction cost required to execute the defined scope together with estimated additional costs for engineering, permitting, bonding, and EPC project management services. This Proposal summarizes the terms for a base cost and cost-plus contract for road construction activities to begin in mid-January 2026, and identifies a maximum projected cost range for budgeting and financing purposes.

Scope Summary:

- 22 miles pioneer road (22' wide x 3' deep screened pit run)
- Side slopes, drainage ditches, winter ice road
- 3 20'x60' Temporary flatcar bridges, 28 culverts (5' x 40' CMP)
- 2 drill pads (3 ac + 5 ac @ 45")
- 2 water reservoirs (5 ac x 15')
- Typar on 5 miles of Oil Well Road segment of project
- Final 7 miles per haul road alignment

ROM Cost Summary:

Item	ROM Amount
Base Installed Construction (ROM low point)	$ 30.0 M
Bonding (10% of Base Construction)	3.0 M
Engineering, Permitting, Surveying & Compliance (10%)	3.0 M
Subtotal – Direct Costs	$ 36.0 M
GLC EPC Project Management Fee (15%)	5.4 M
TOTAL PROJECT ROM (Paid to GLC)	$ 41.4 M

Construction ROM Range: $30 M (low) to $40 M (high)
Recommended Planning Target: ~$42 M (Low) – $56 M (High)

A $ 7.75 M Down Payment is due by January 15, 2026 (See Page 3)

This ROM Budget Proposal is valid through February 5, 2026.

DENALI PETROLEUM & GAS COMPANY
2026 Road Construction Program – Phase 1
Spend Plan & Notes

SPEND (PLANNING)

The project is expected to be executed in logical phases to align cash flow, risk, and permitting windows.

Project	Scope	ROM Spend
Winter Access	2026 & 2027 Ice road construction, mobilization, early clearing	$6 – $8 M
Base Road Construction	Gravel production & placement, culverts, Typar, drainage	$15 – $20 M
Structures	Flatcar bridges, approaches, stabilization	$2 – $3 M
Pads & Reservoirs	Pad construction, reservoir excavation, final shaping	$4 – $5 M
Completion & Contingency	Punch list, weather & permitting delays, unknowns	$3 – $4 M
Base Installed Construction		$30 - $40 M

Notes:

Adjusted Margin Assumptions:

- Construction Margins: 10% of installed construction (conservative, competitive)
- Grant Lake Corporation EPC Participation: 15% of gross project value
- These assumptions reduce investor sensitivity to self-dealing while maintaining strong alignment between execution and ownership.
- These allowances are carried for financing and risk planning.
- Actual bond premiums and permitting costs may be lower but are conservatively budgeted at this stage.

Down Payment:

- Supports project mobilization costs through April 2026 including bonding, engineering, permitting, and February 2026 Ice Road Construction and equipment and materials placement at multiple construction sites before spring breakup, required to maintain February 2027 drill rig transport to drill site 1, assembly and spring drilling schedule.

Appendix I
NuTech Energy Alliance
Trail Ridge Unit 1 Analysis

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NUTECH
VISIONARY RESERVOIR INTELLIGENCE

ADVANCED RESERVOIR CHARACTERIZATION

Evaluated For:

ASRC ENERGY SERVICES

Project #: 029562

Completed: 9/29/2025

Company	UNION OIL CO OF CALIF				
Well	TRAIL RIDGE NO 1				
Field	TYONEK				
County	MAT-SU	State	ALASKA	Country	USA
Location	1068.5' S. & 381.5' W OF NE.				
	LAT.61.8426655 LONG. -151.0836039				

Section	9	Township	20N	Range	10W	API Num	50283200650000
Permanent Datum	MSL			Elevation	222	K.B.	249
Log Measured From	KB	,	27	Above Perm Datum		D.F.	248
Drilling Meas From	KB					G.L.	222

	Run 1	Run 2	Run 3
Date	01-06-1980	23-06-1980	20-08-1980
Depth - Driller	1020	4011	..
Depth - Logger	1011	4003	..
Btm Log Interval	1005	3995	10604
Top Log Interval	108	982	4000
Casing - Driller	30" @ 110	20" @ 982	13 3/8" @ 4008
Casing - Logger	108	982	4000
Bitsize	17.5"	12.25"	12.25"
Type Fluid in Hole	GEL	GEL	FGM
Dens. /Visc.	9.8 / 190	9.3 / 88	72.0 / 59
pH / Fluid Loss	7.0 / 4.0	12.0 / 9.2	10.0 / 5.1
Source of Sample	CIRCULATED	CIRCULATED	CIRCULATED
Rm @ Meas. Temp	7.6 @ 66	0.96 @ 75	2.42 @ 60.0
Rmf @ Meas. Temp	10.6 @ 62	0.60 @ 75	1.87 @ 62.0
Rmc @ Meas. Temp	5.21 @ 68	0.90 @ 75	2.83 @ 62.0
Source: Rmf / Rmc	M / M	M / M	M / M
Rm @ BHT	250 @ --	0.78 @ 92	.. @ ..
Max. Rec. Temp.	--	92	..

	Run 4
Date	4-09-1980
Depth-Driller	12028
Depth-Logger	12017
Btm Log Interval	12011
Top Log Interval	9800
Casing-Driller	13 3/8" @ 4008
Casing-Logger	4000
Bitsize	12.25"
Type Fluid in Hole	FGM
Dens. / Visc.	75 / 52
pH / Fluid Loss	10.5 / 4.6
Source of Sample	CIRCULATED
Rm @ Meas. Temp	1.98 @ 70
Rmf @ Meas. Temp	1.68 @ 52
Rmc @ Meas. Temp	3.34 @ 52
Source: Rmf / Rmc	M / M
Rm @ BHT	1.1 @ 126
Max. Rec. Temp.	126

**** NOTES ****

The NuLook provides for a normalized and consistent reservoir description, enabling the NuLook process calibration sets to be predictive within a field. The NuLook process results are summarized in the log display section of this report.

NuLook's Shale Analysis processing adjusts the effective porosity solution for the total organic content which can be derived from the open hole logs with a localized calibration back to core results.

NuLook's Fracture Analysis processing is used to indicte the probablitity of natural fracturing of the reservior. Any increase in production rates caused by the presence of natural fractures as identified by the FIV analysis cannot be quantified without extensive study and is not represented in this analysis.

NuLook's Thin Bed Analysis is used in cases of low contrast/highly laminated intervals, conventional log responses lack the vertical resolution to properly characterize these intervals. NuTech has developed proprietary processes using standard triple combo data sets to dramatically improve the responses of conventional logs by magnifying the inflection points at each depth interval to increase vertical resolution. This analysis will closely match the resolution of image tools and results in improved estimates of reservoir quality and volumes.

** Nulook Log Curve Names and Descriptions **

Track #	Curve Name	Description
1		Correlation track. This is the original log data and includes SP, gamma ray (GR), and caliper.
2		Reservoir quality flags track. The flags are from the NuLook petrophysical analysis and indicate the risk rating for the intervals. Three flags are required for a #3 rating, four flags for a #2 rating, and five flags for a #1 rating. The yellow flag will appear when the threshold for vclay, free fluid, and kmin are met. The dark cyan flag appears when the free water is less than the set threshold for free water production. The black flag will appear when the hydrocarbon volume versus free water is greater than the set threshold which is a percentage of the volume. The green flag appears when the permeability exceeds a fair threshold. The red flag will appear when the permeability exceeds a good threshold. The threshold values are determined by area and from client information and experienced. A light cyan flag on the right of the track indicates when free water exceeds the set threshold. For the geo-textural properties display, the tension curve is also displayed in this track.
3		Depth track. This track displays the depth and plots the caliper in order to give a visual illustration of the hole integrity. For intervals where the NuSource shale vision processing is utilized, a purple shalemod flag will be present.
4		Resistivity track. This track displays the original logged resistivity data. RWG is Rw used in analysis at formation temperature.
5		Porosity log track. This track displays the original log porosity data (density, neutron and acoustic) in limestone or sanstone units as appropriate, along with Pef.
6		Miscellaneous track. This track displays DRHO, micro-log, and mud-log total gas data.
7		NUSPEC track. This track shows a variable density display of the pore size distribution.
8		Lithology track. This track shows the volumetric percentages of the lithological components of the formation, as identified by the NuLook petrophysical analysis.
9		Volumetric analysis track. This track displays the water saturation (Sw), effective porosity (PHIE), bulk volume irreducible (BVI), and bulk volume water (BVW) curves, as output from the NuLook petrophysical analysis.
	SW	Sw is a blue curve presented on a 100 to 0 scale from left to right across half of the track.
	BVI	BVI is presented in dark cyan and is scaled in porosity units across the full track.
	BVW	BVW is the light gray curve and is scaled in porosity units across the full track.
	PHIE	PHIE is shown as a red curve and is scaled in porosity units across the full track. The free fluid volume is the difference between BVI and PHIE. The volume of hydrocarbons is shown in black. Free water is indicated with a light cyan color.All porosity curves are scaled in porosity units of 0 to 30% or 0 to 60%.
10		Permeability track.
	NUPERM	Textural permeability (milidarcies) as output from the NuLook petrophysical analysis. Permeability is presented with a color spectrum trending from blue to red as permeability increases. The scaling is determined from the values selected for the risk ratings and depends on the basin and formation.
	PERMSH	Shale model permeability (microdarcies) as output from the NuSource shale vision analysis, when appropriate. Permeability is presented in purple to indicate the scale shift to microdarcies for the shale intervals.
11		FIV Track This track displays the flags generated by the Fracture Intensity Vision process. BLACK FLAG==>caliper, BLUE FLAG==>DRHO, GREEN FLAG==>Acoustic/Density, LT RED FLAG==>Resistivity Ratio 1, DK RED FLAG==>Resistivity Ratio 2

```
                              **************************
                              ***     PARAMETERS     ***
                              **************************

Rw  =   TOP - 1608'     4.00  @ 75 F     .   M =  TOP - BTM          2          .   Perm Model:                         .  Flag Cutoffs
Rw  =  1608'- 5400'     1.60  @ 75 F     .   N =  TOP - BTM          2          .                                       .
Rw  =  5400'- 7045'     4.00  @ 75 F     .                                      .    Coeff = TOP - BTM        FF-12     .    VClay =  .4      Free Fluid = .03
Rw  =  7045'- 9181'     2.00  @ 75 F     .                                      .                                       .    Kmin  =  .1      Free Water = .01
Rw  =  9181'-11678'     1.00  @ 75 F     .                                      .                                       .    Kfair =   1      TooMuchWtr = .015
Rw  = 11678'- BTM '     0.40  @ 75 F     .                                      .                                       .    Kgood =   10     LowHydrcbn = .6
Rhom  = TOP - BTM       2.65             .                                      .                                       .
Rhof  = TOP - BTM       1.0              .                                      .                                       .
                                         .                                      .                                       .
DTMtx = TOP - BTM       55.6             .                                      .                                       .
NEUT  = TOP - BTM       SAND             .                                      .                                       .
```

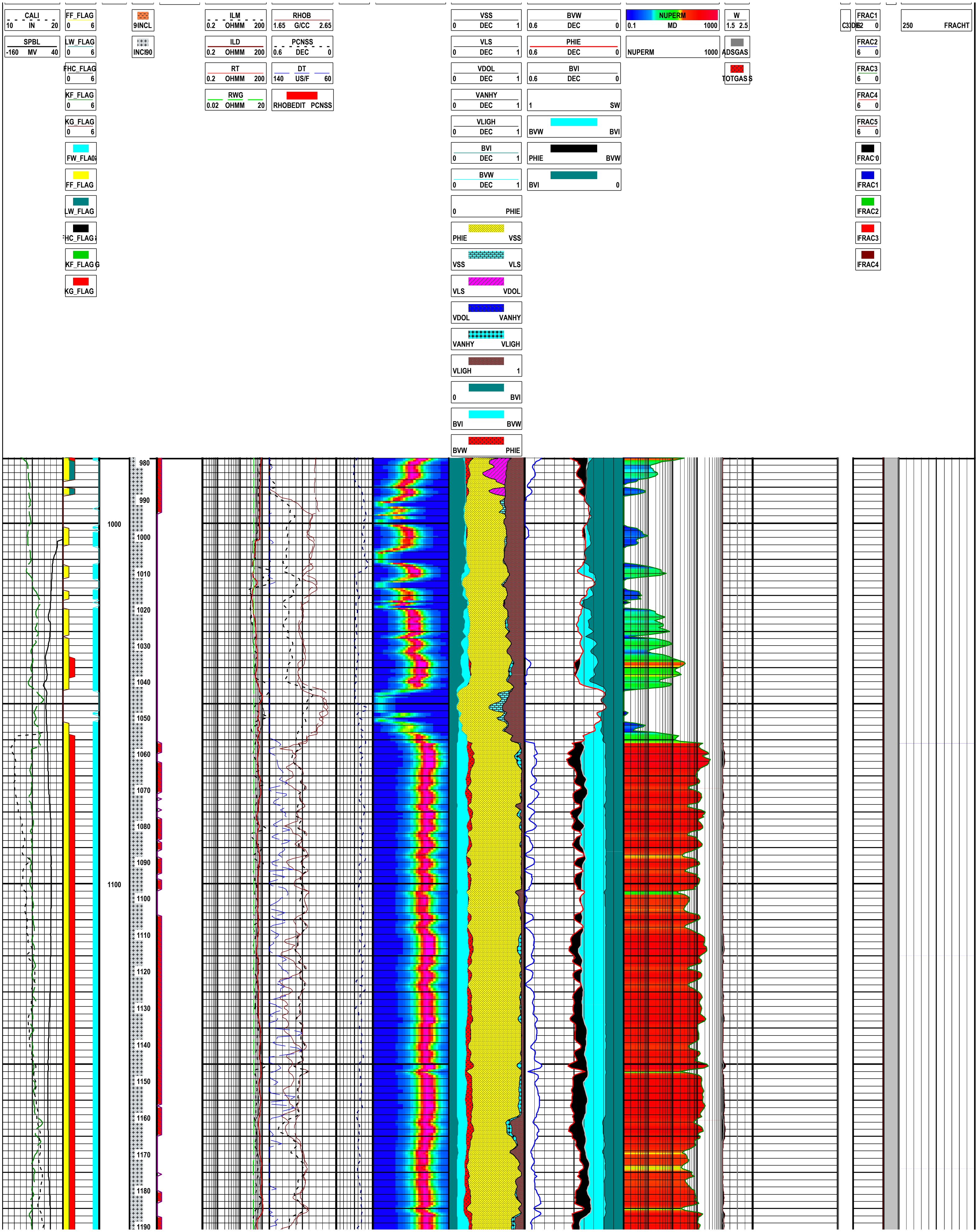
Project ID: ASRC ENERGY - 29562
Analyst : HH
Comments :

NULOOK PROCESSES: STANDARD (X) ; SHALE ( ) ; FIV (X) ; THINBED ( ) ; ES ( ) ; GEOMECHANICAL ( )
PRIORITY OPTION: STANDARD (X) ; PRIORITY ( ) ; RUSH ( ) ; PRELIMINARY ( )

```
                              **********************
                              ****    REMARKS   ****
                              **********************
```


TRAIL RIDGE NO 1
29 Sep 2025 @ 9:34
DEPTH (FT)
Interval: 982.00 to 12010.00
Depth Scale Ratio: 1/240

TRACK 1	TRACK 2	DEPTH	TVD	EDITFLG	TRACK 4	TRACK 5	TRACK 6	TRACK 7	TRACK 8	TRACK 9	TRACK 10	ADSGAS	ODE1	TRACK 11	FIV	FRACHT
0 0	0 0	FT	FT	0 10	0 0	0 0	0 0	0 0	0 0	0 0	0 0	SCF/TON 0 100	26	0 0	01	250 0
GRC	FW_FLAG	TRACK 3	INCL		SFL	RHOBEDIT	DRHO	BIN	PHIE	SW	NUPERM	TOTGAS	ODE2	FRAC		FINT
0 GAPI 150	6 0	0 0	85 DEG 95	0 EDITFLG	0.2 OHMM 200	1.65 G/CC 2.65	-0.25 G/CC 0.25	0 0.1	0 DEC 1	1 DEC -1	0.1 MD 1000	SCF/TON 0 100	23	0 DENSITY	FIV	0 4



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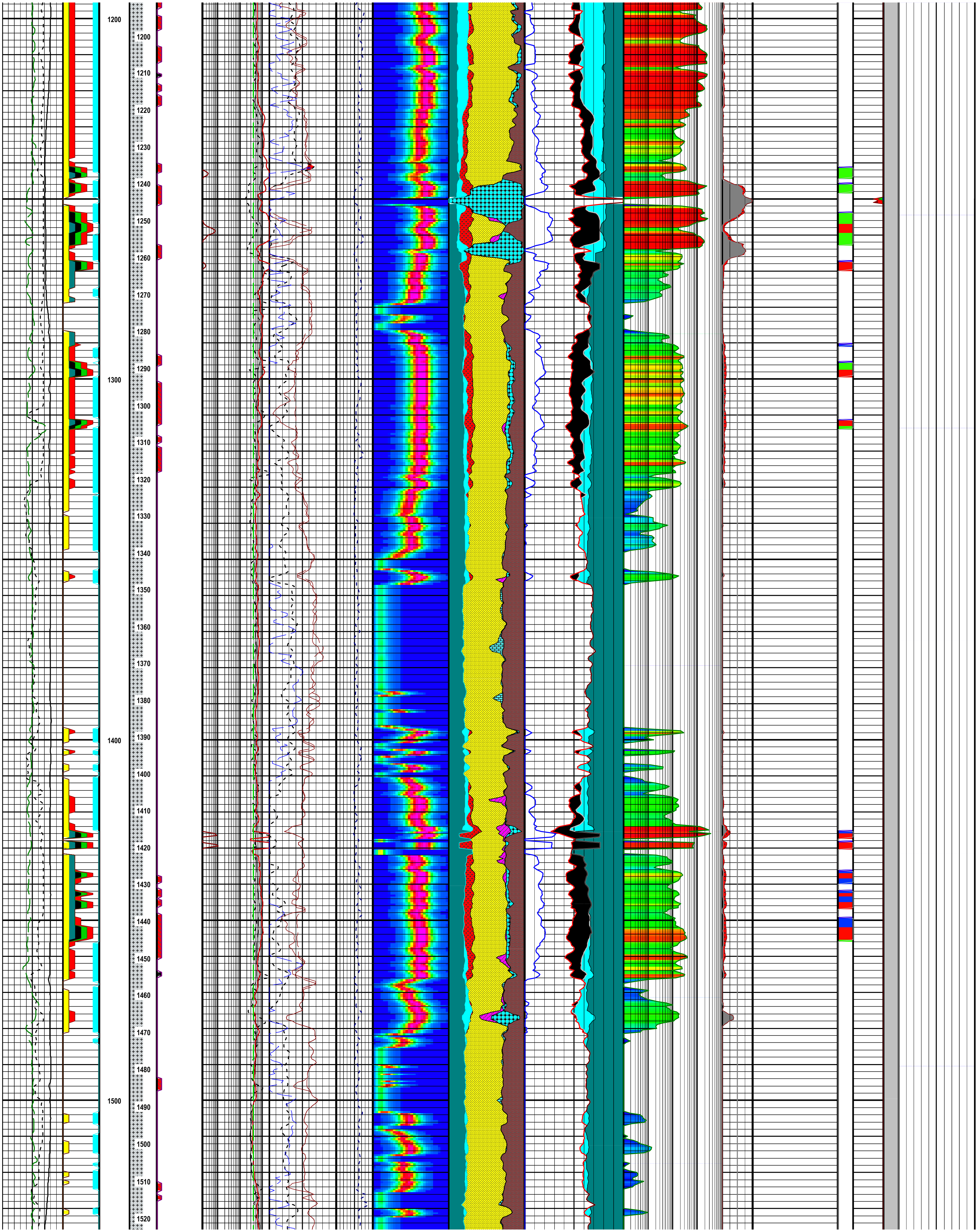
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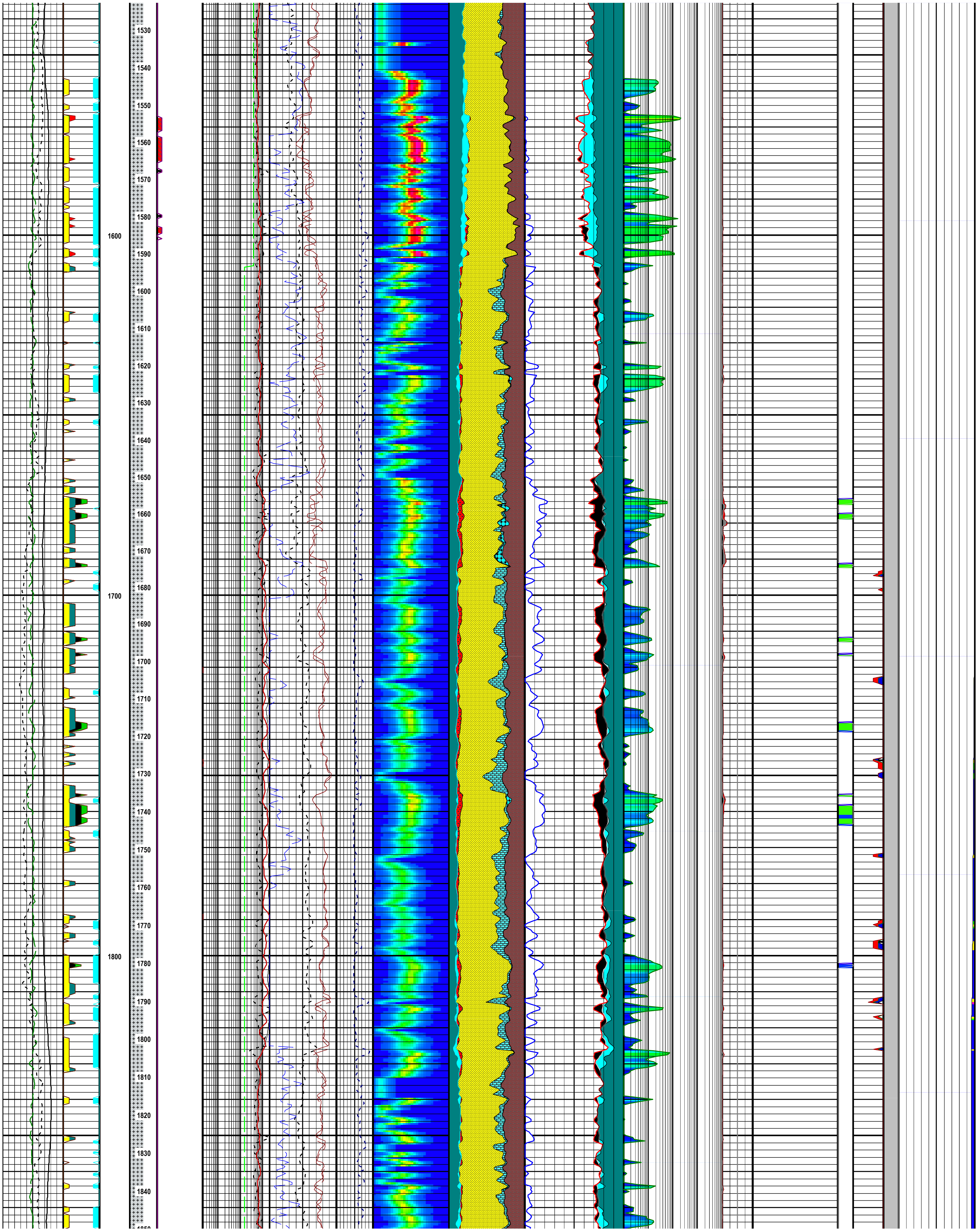
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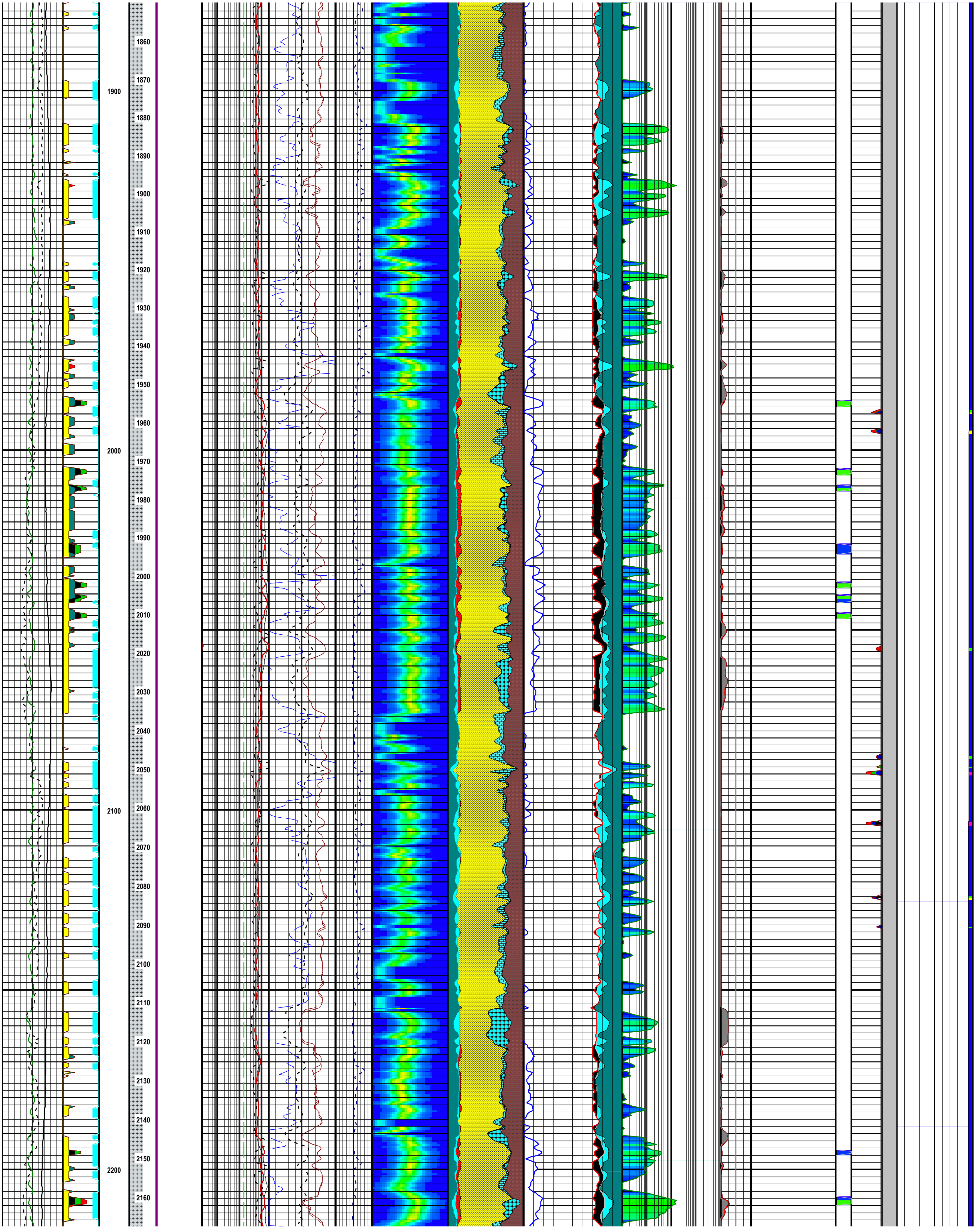
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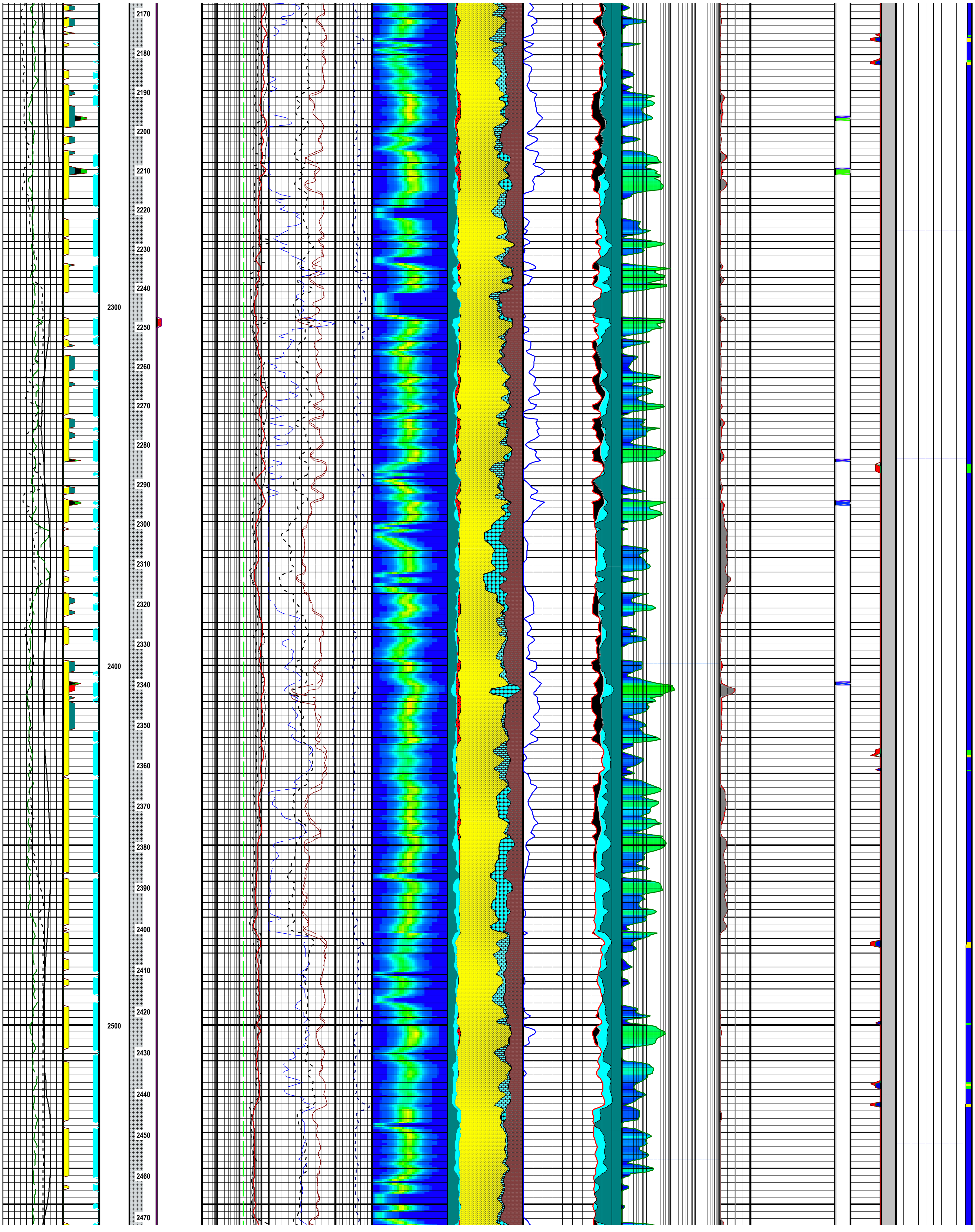
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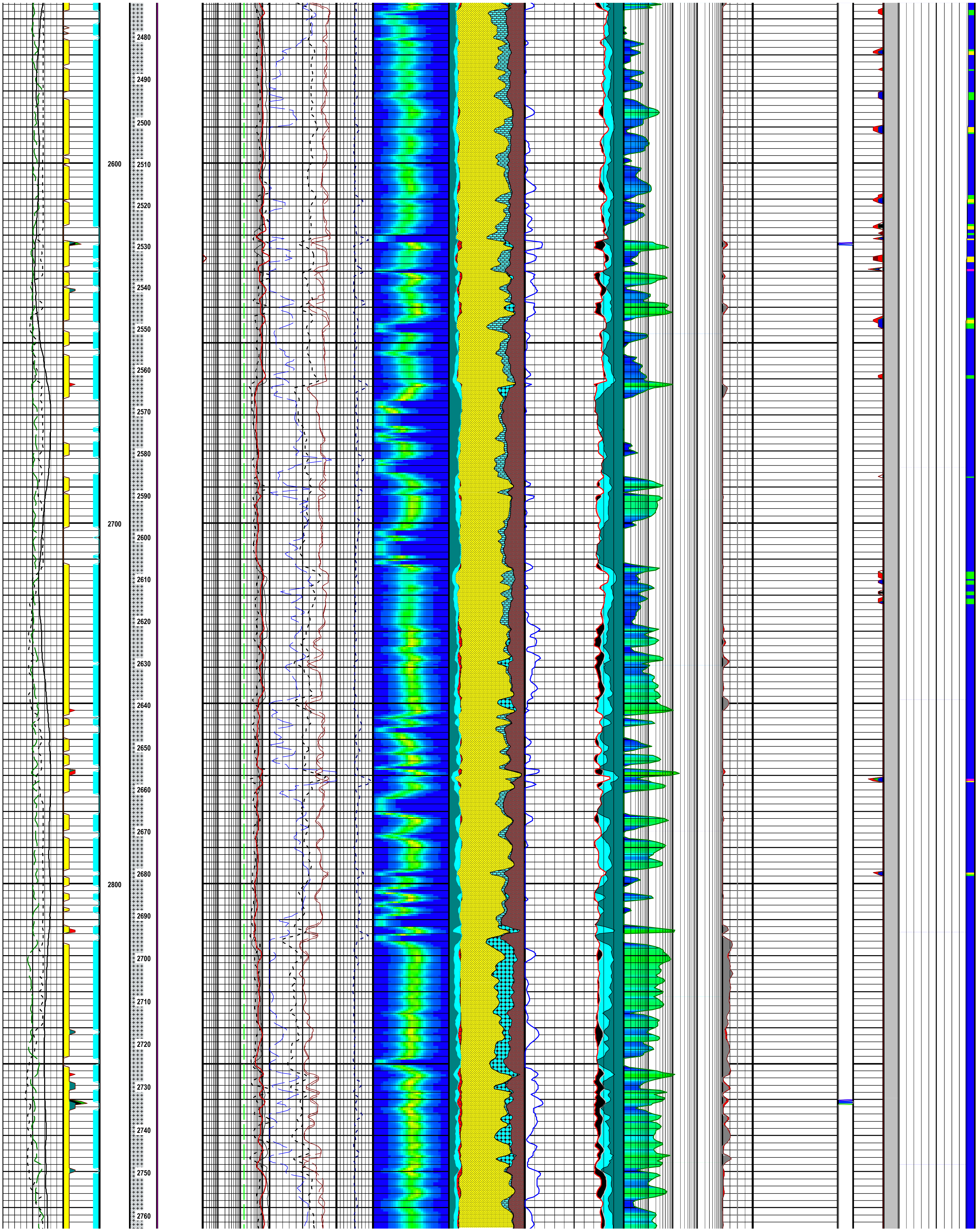
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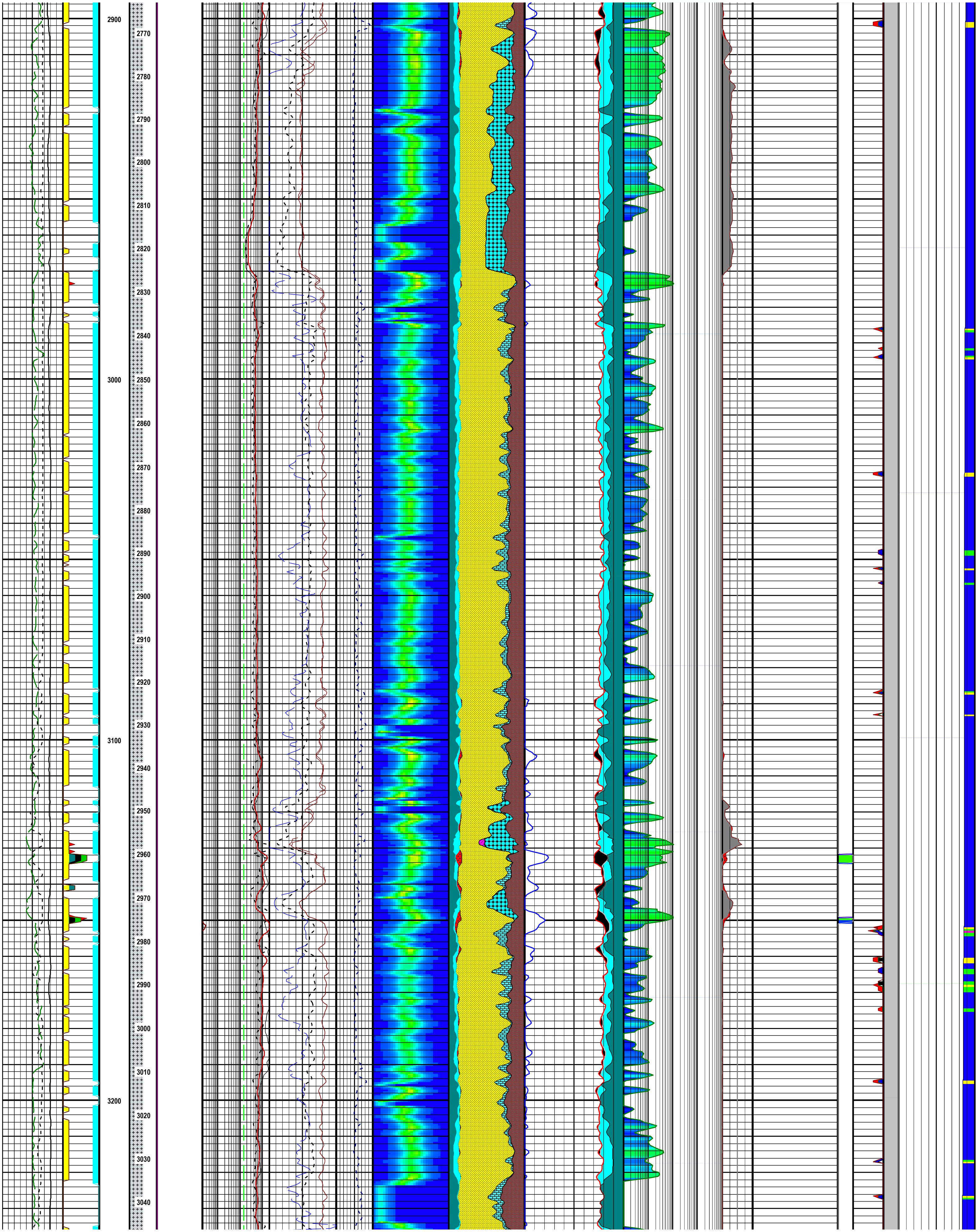
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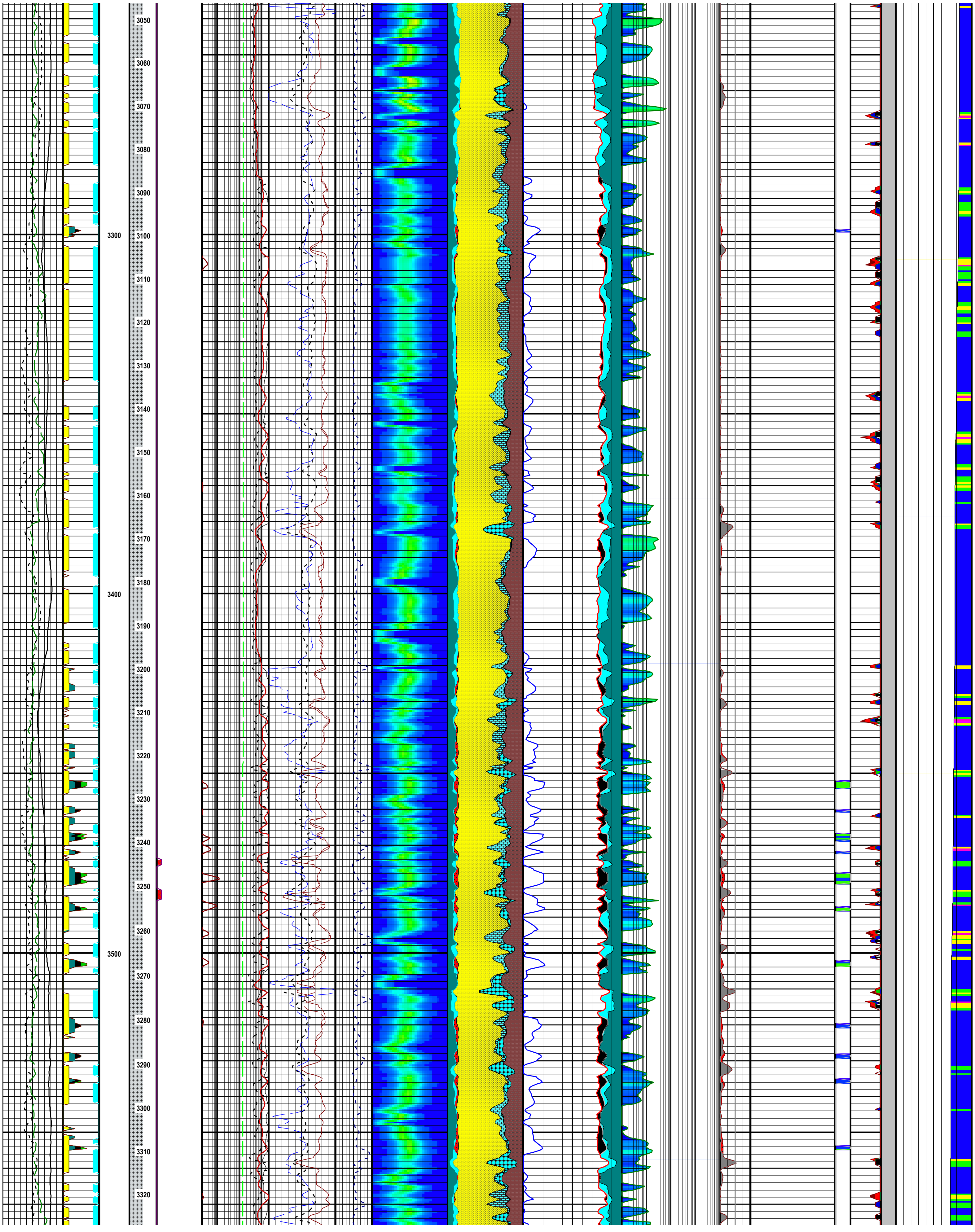
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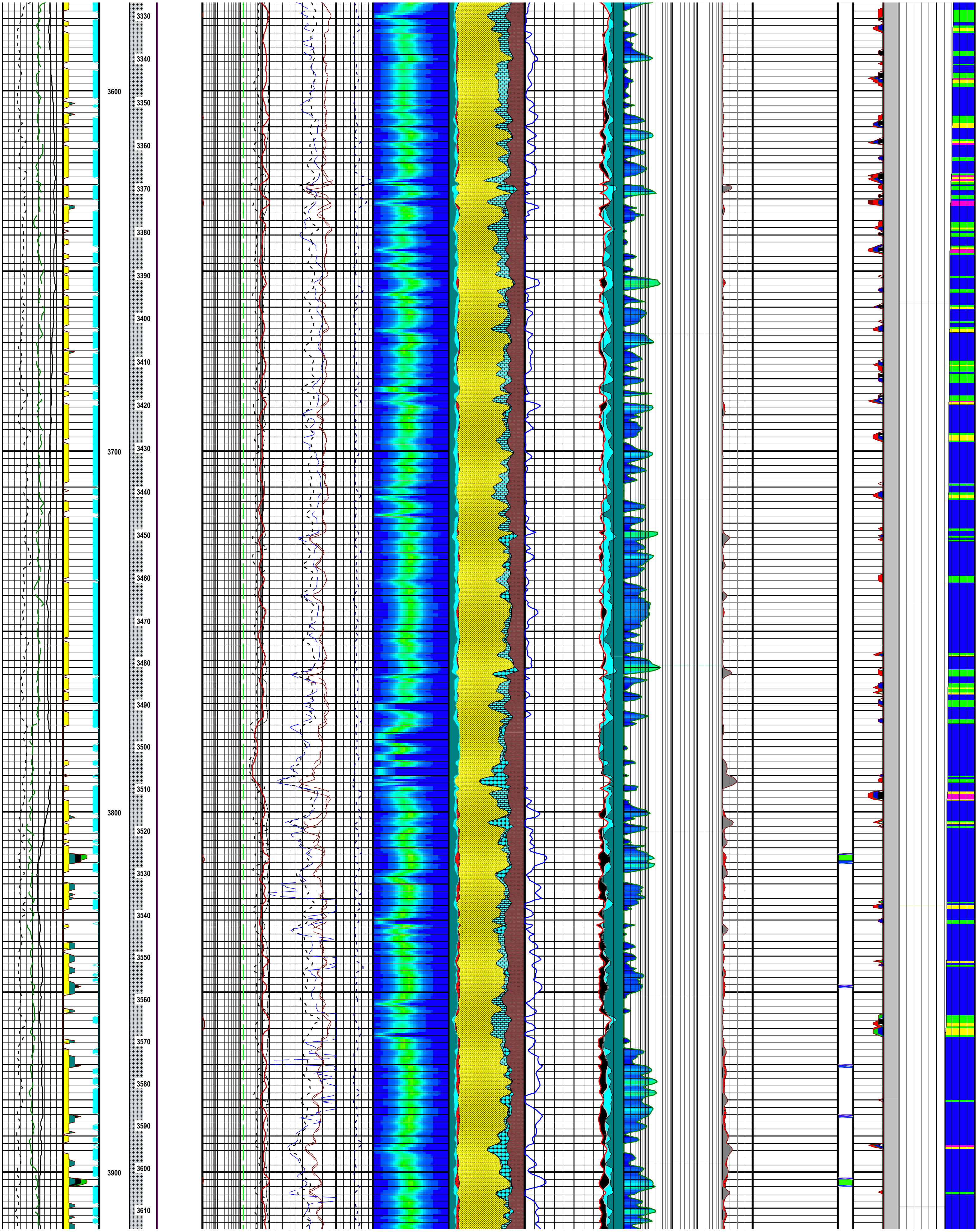
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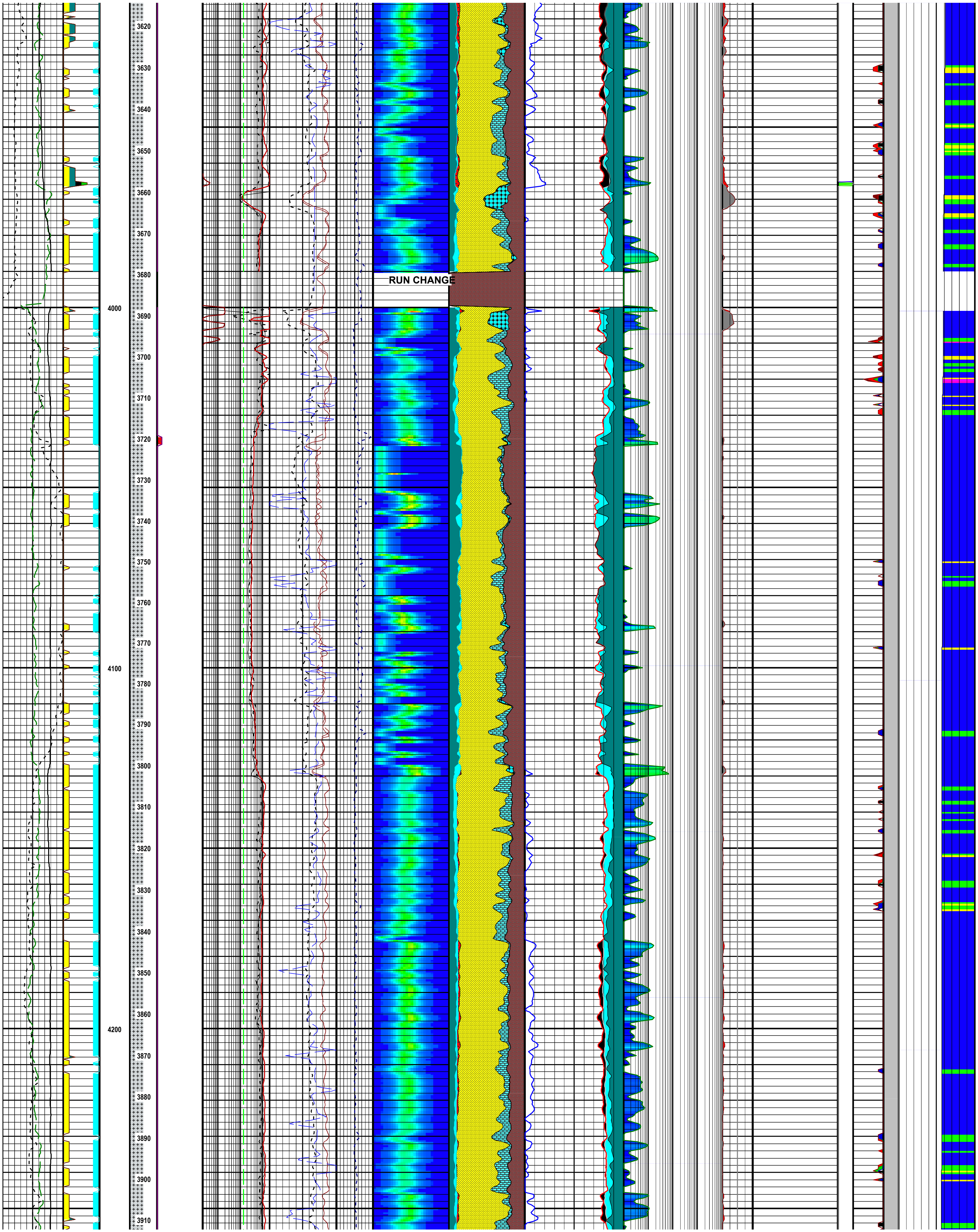
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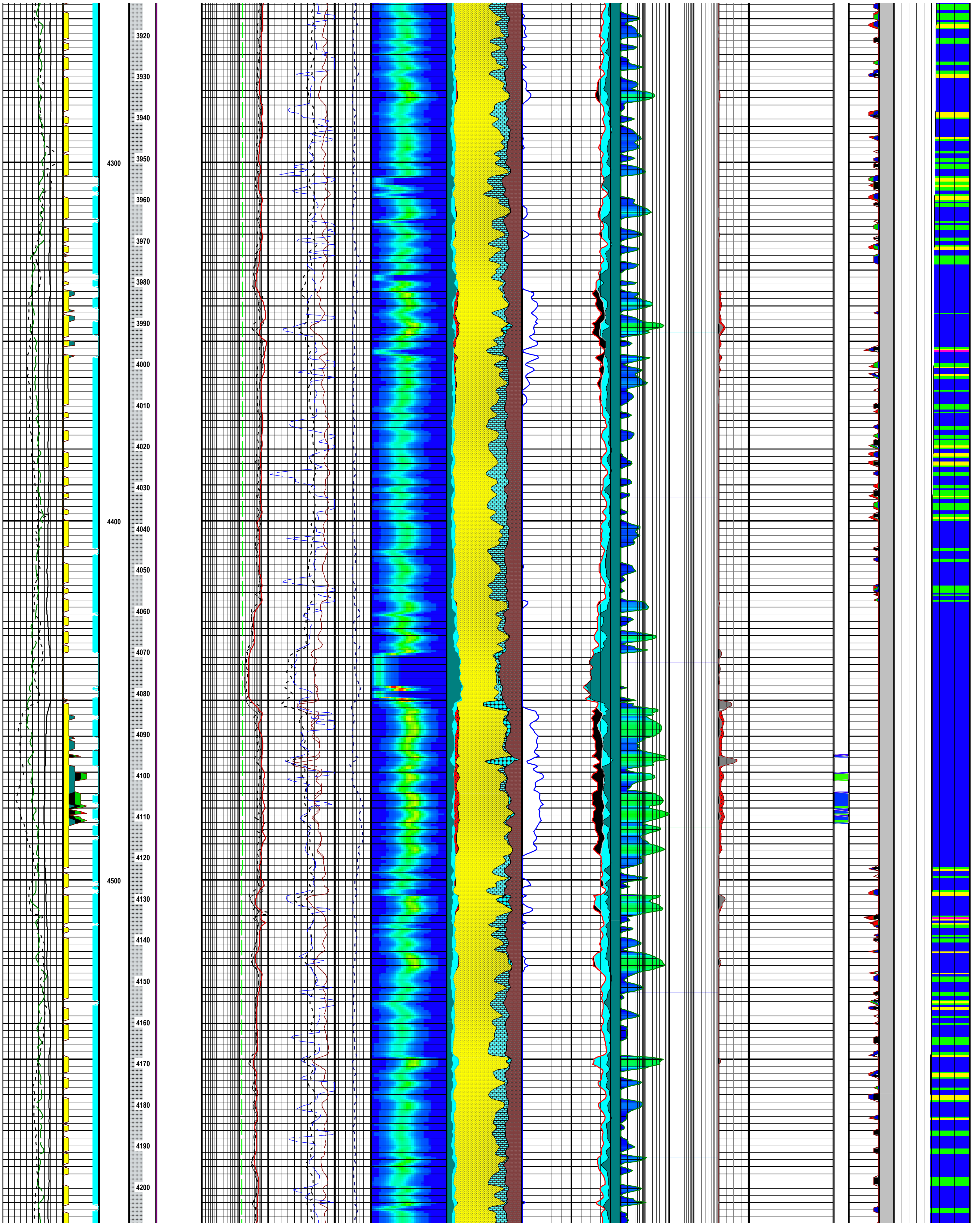
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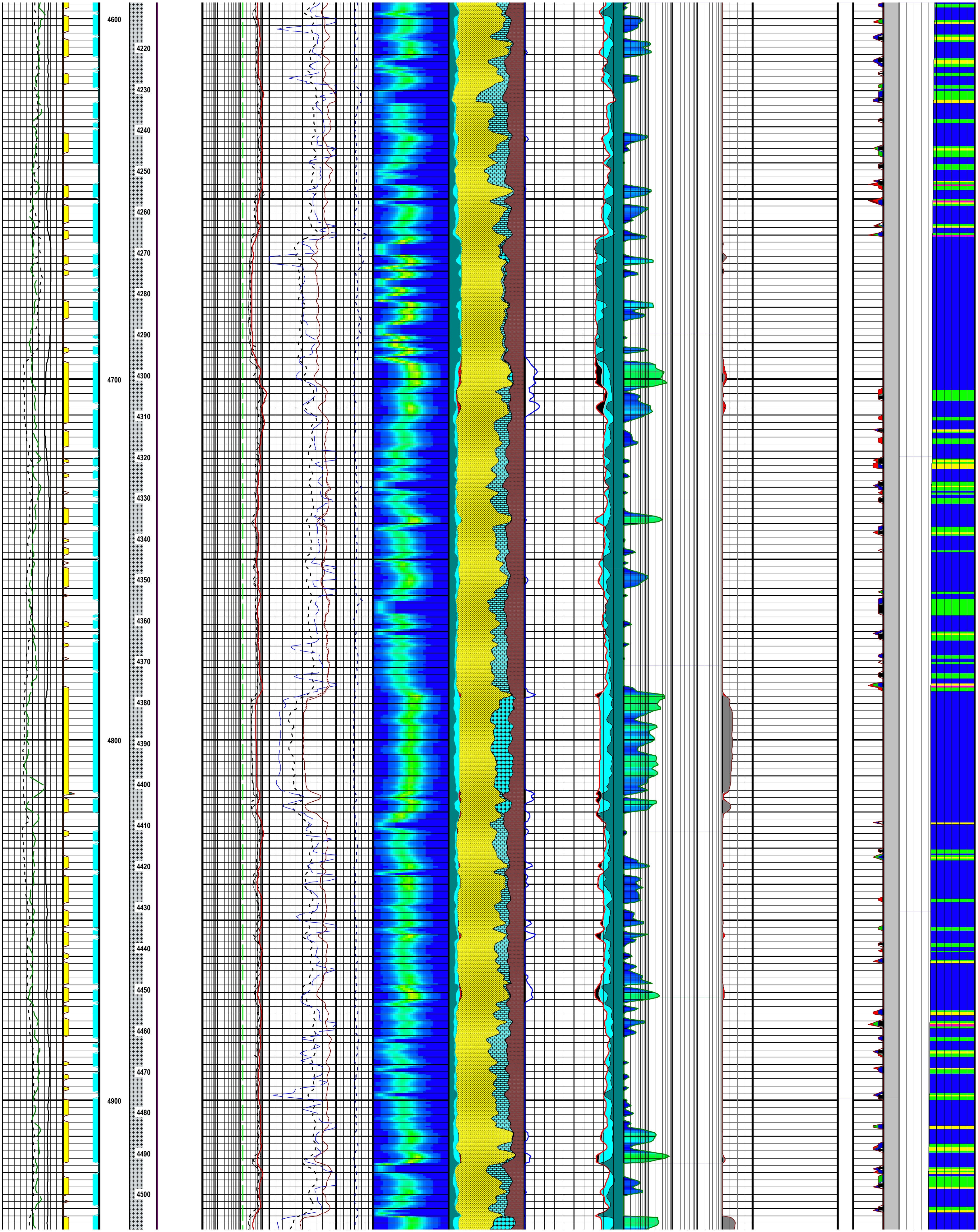
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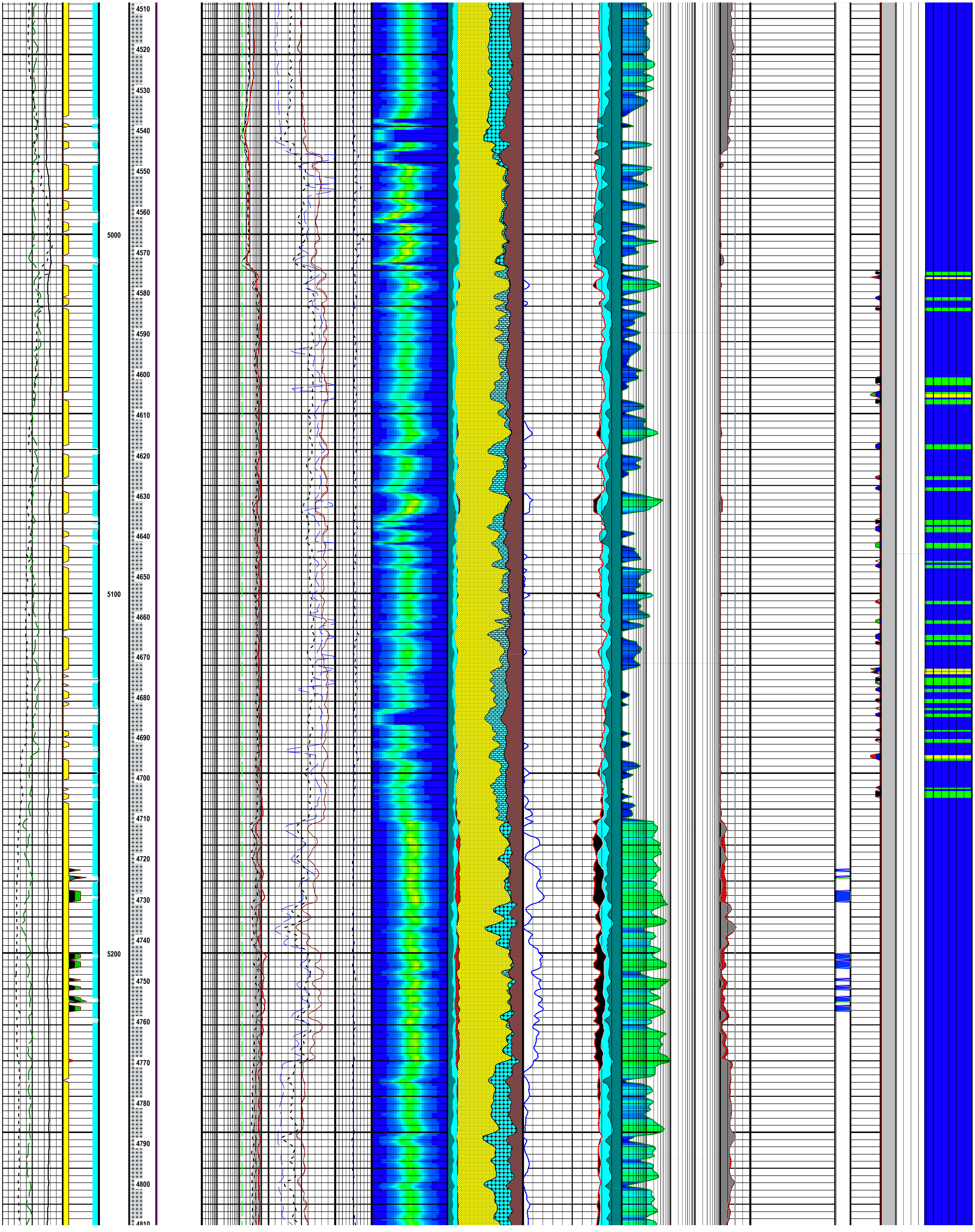
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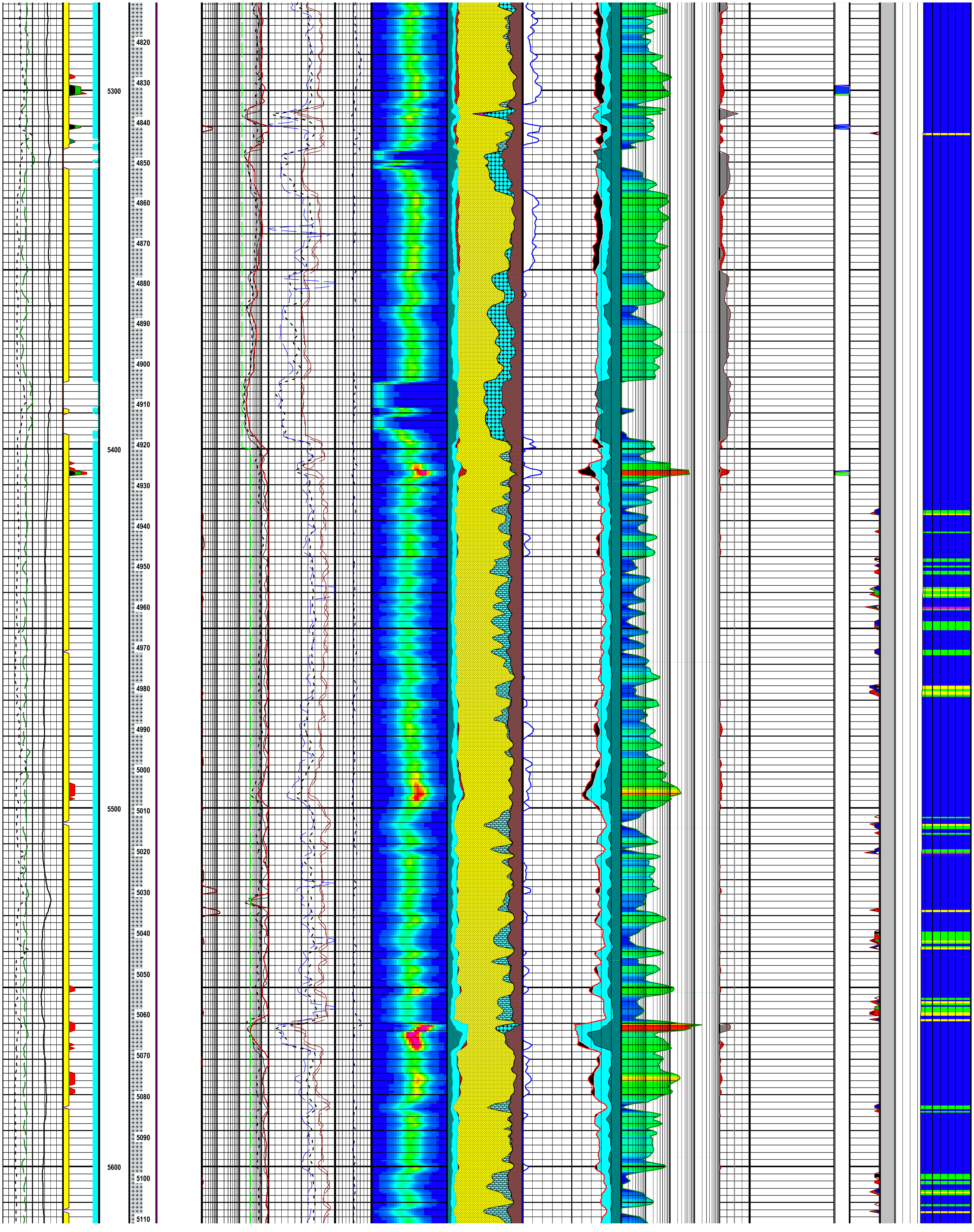
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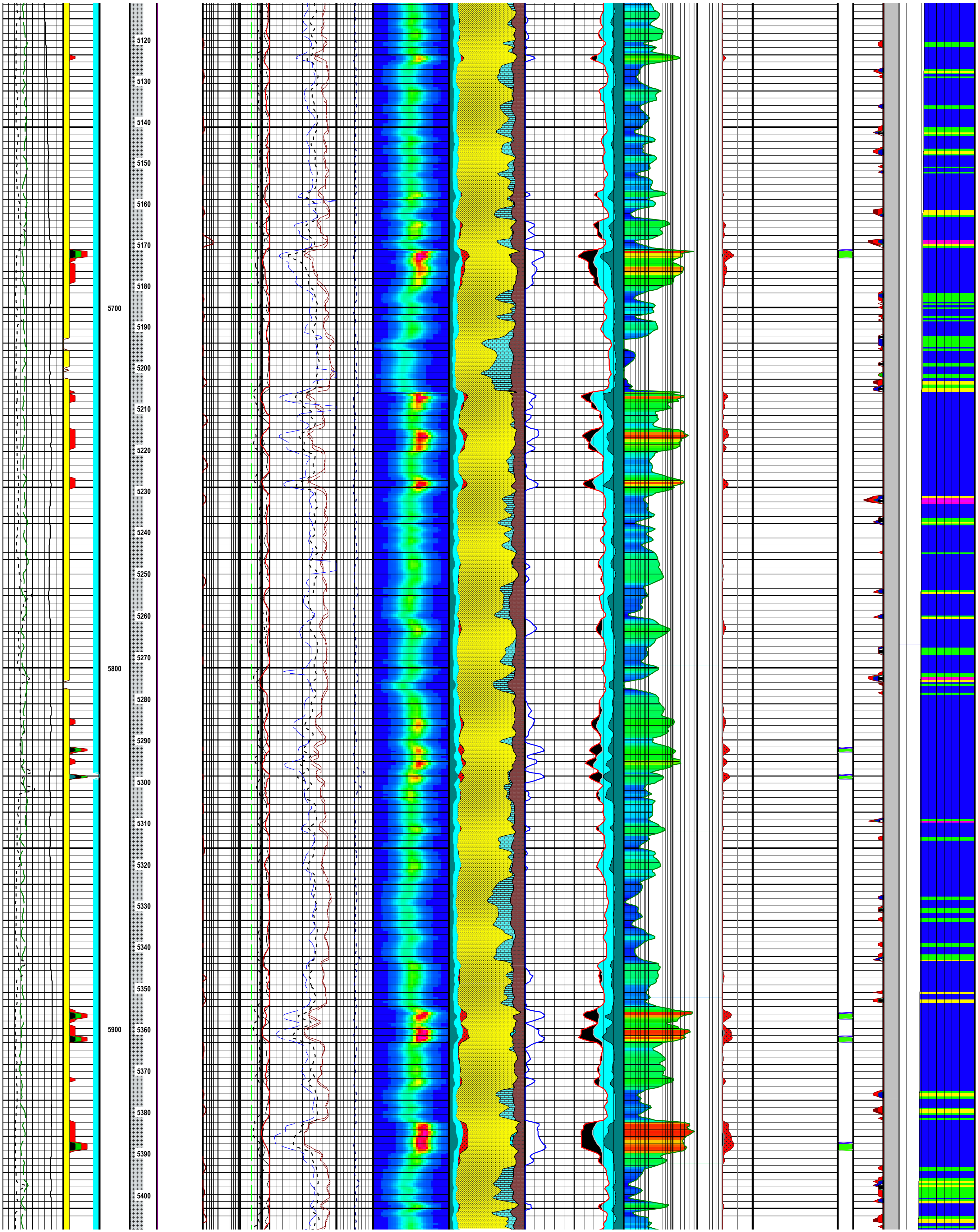
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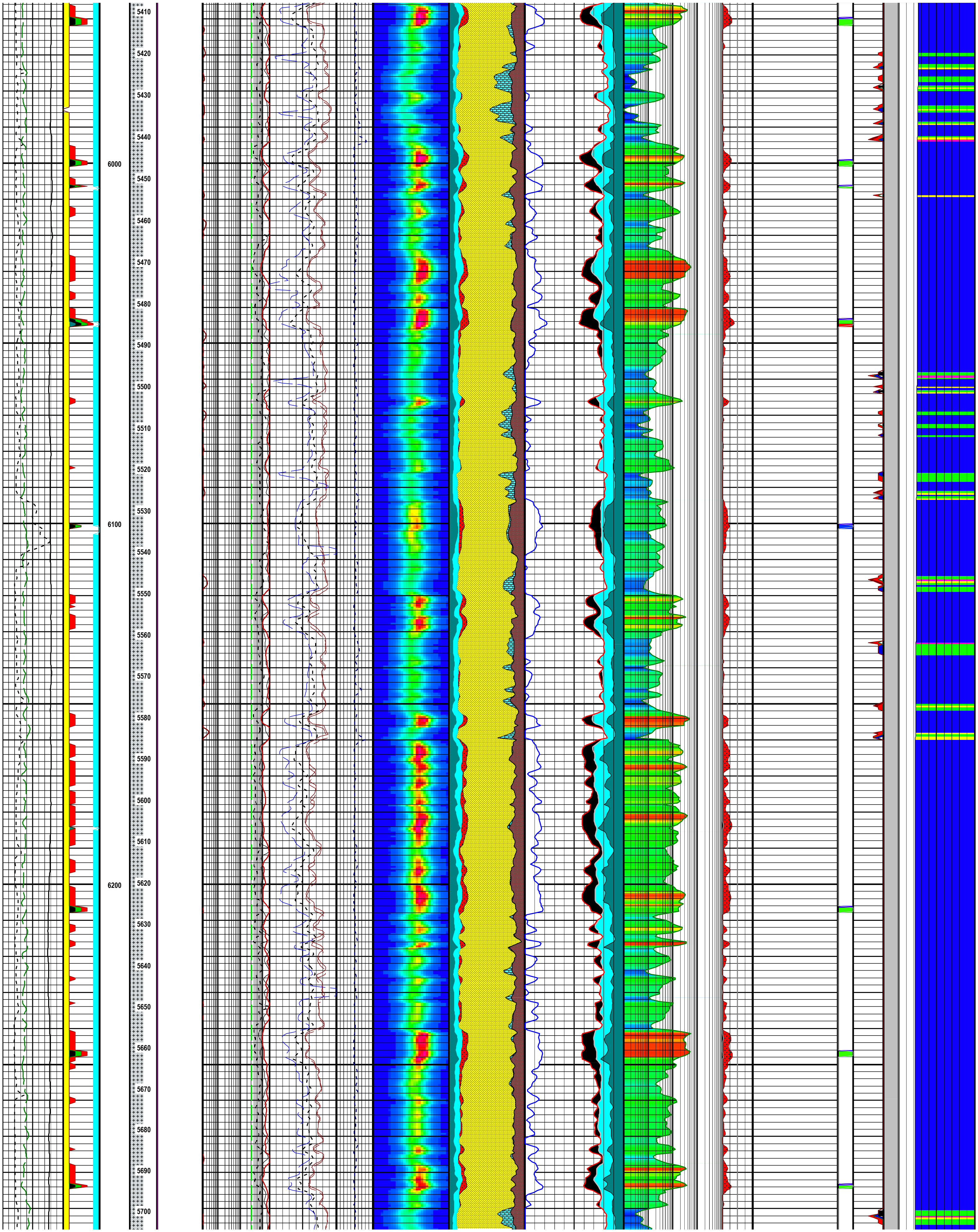
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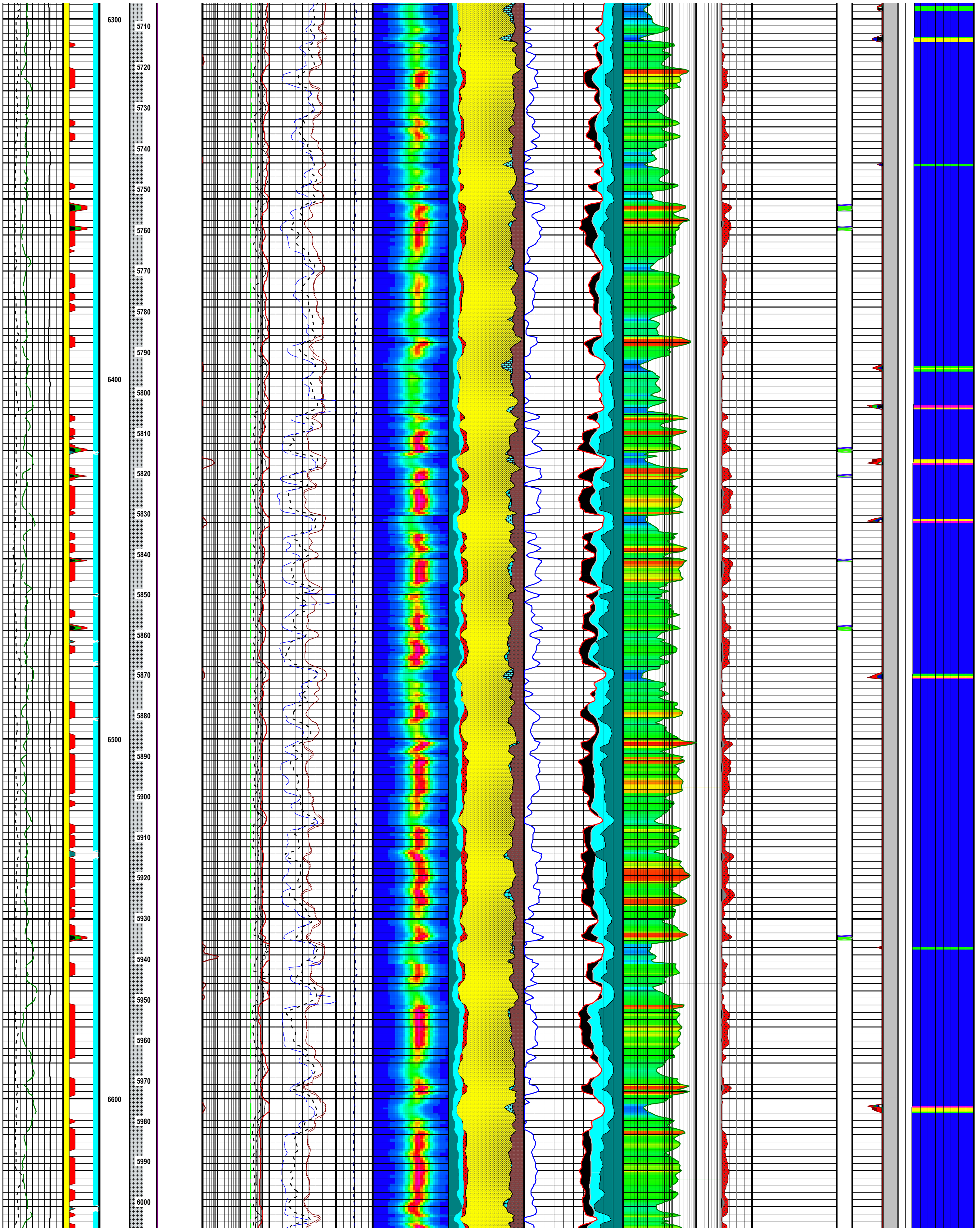
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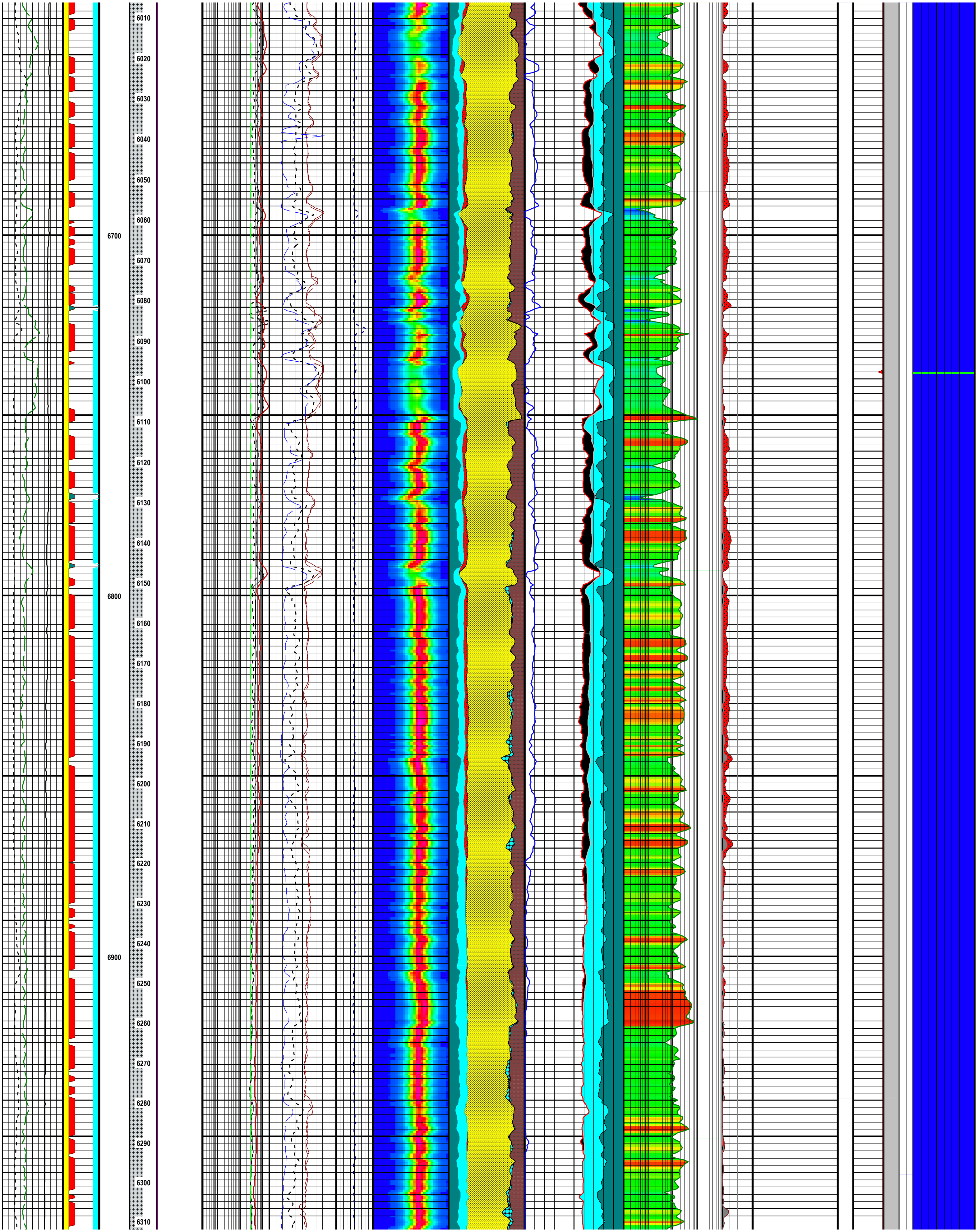
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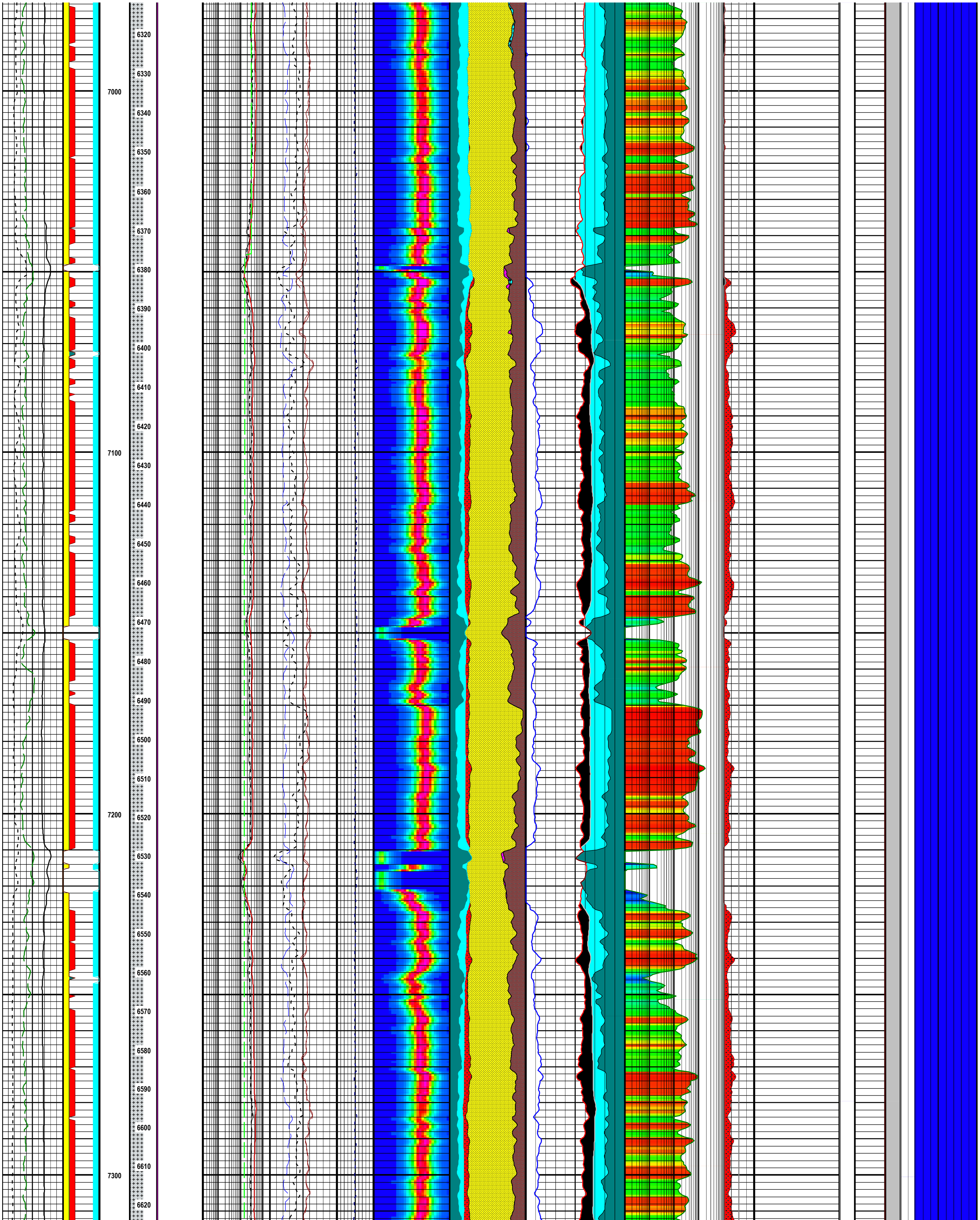
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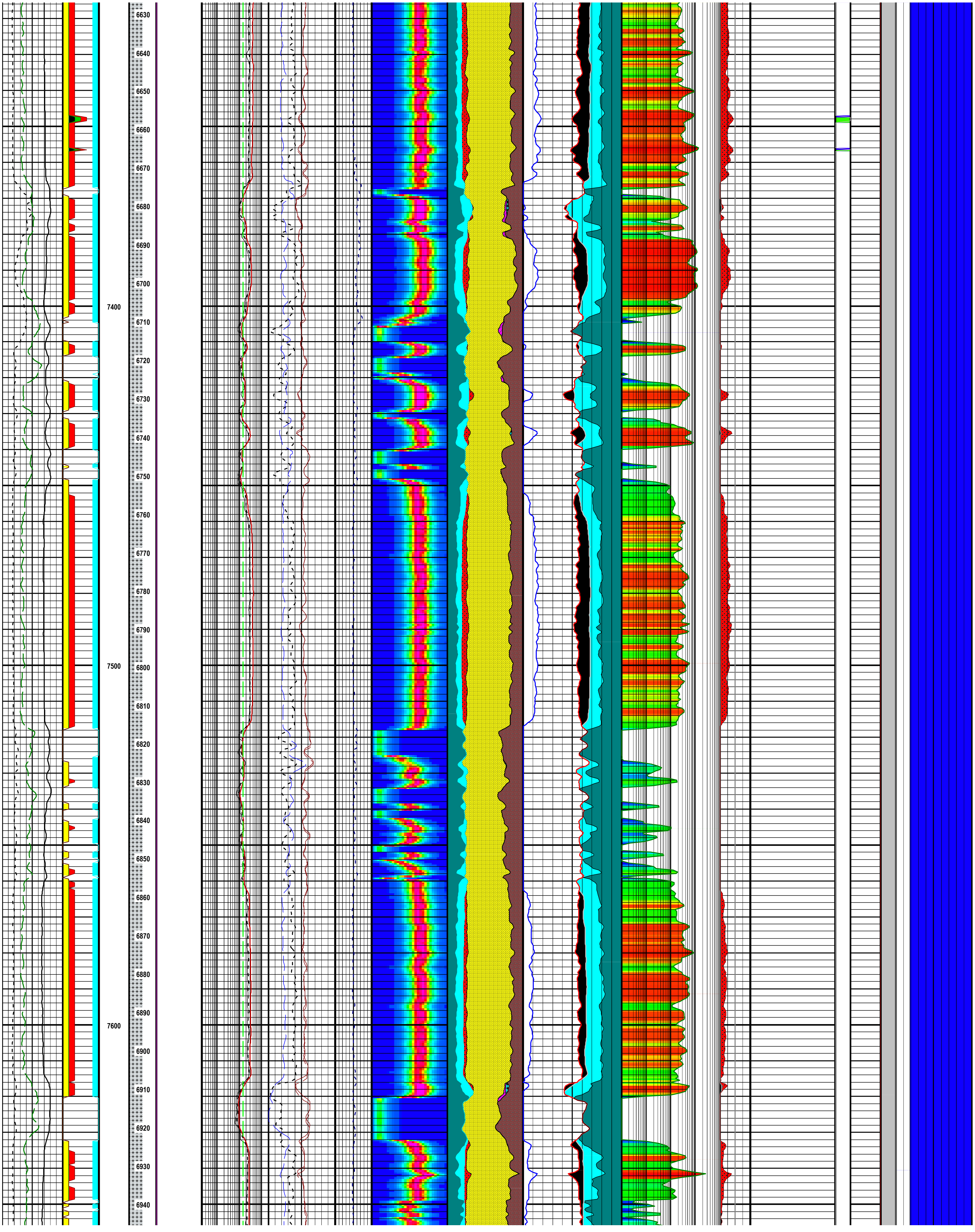
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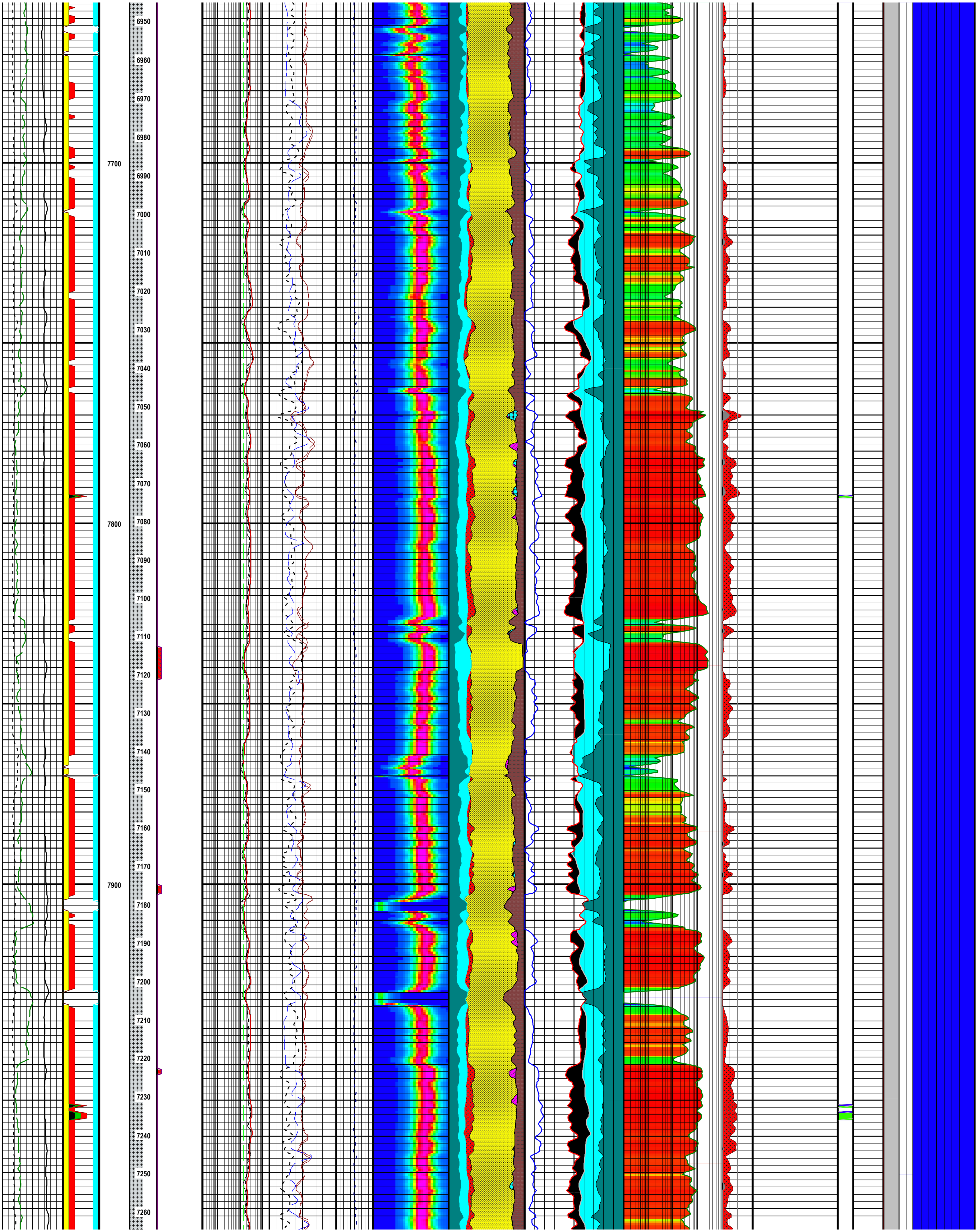

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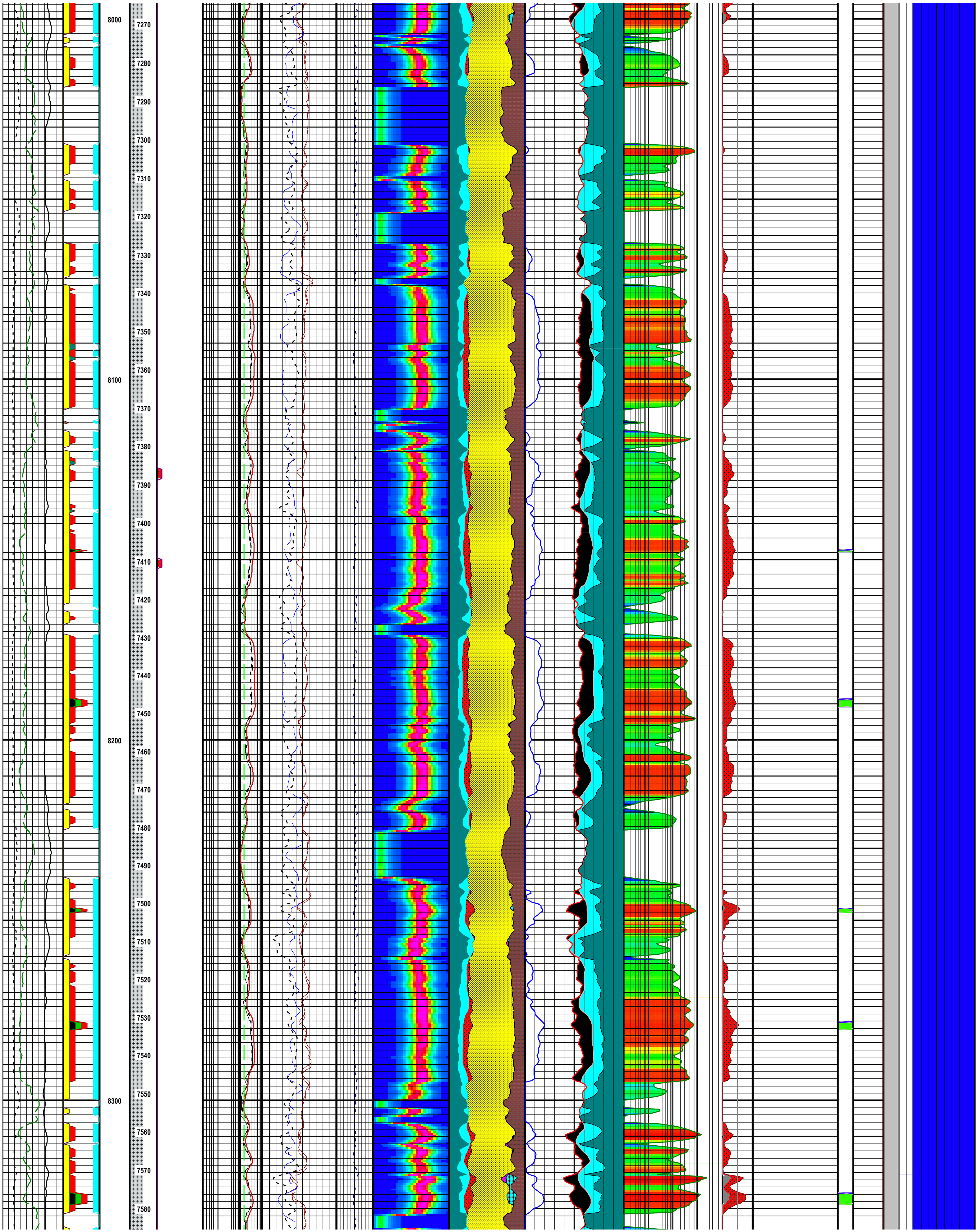
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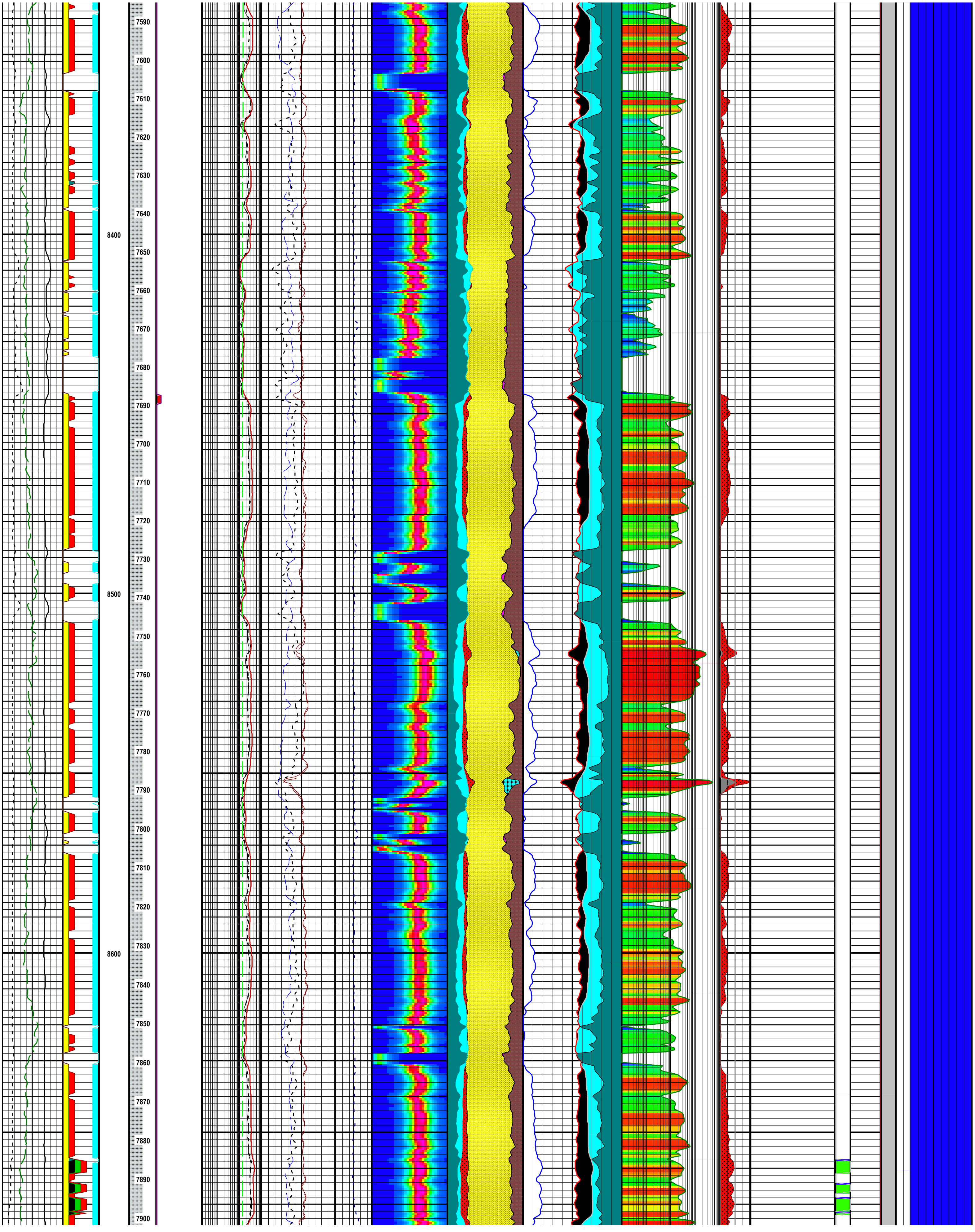
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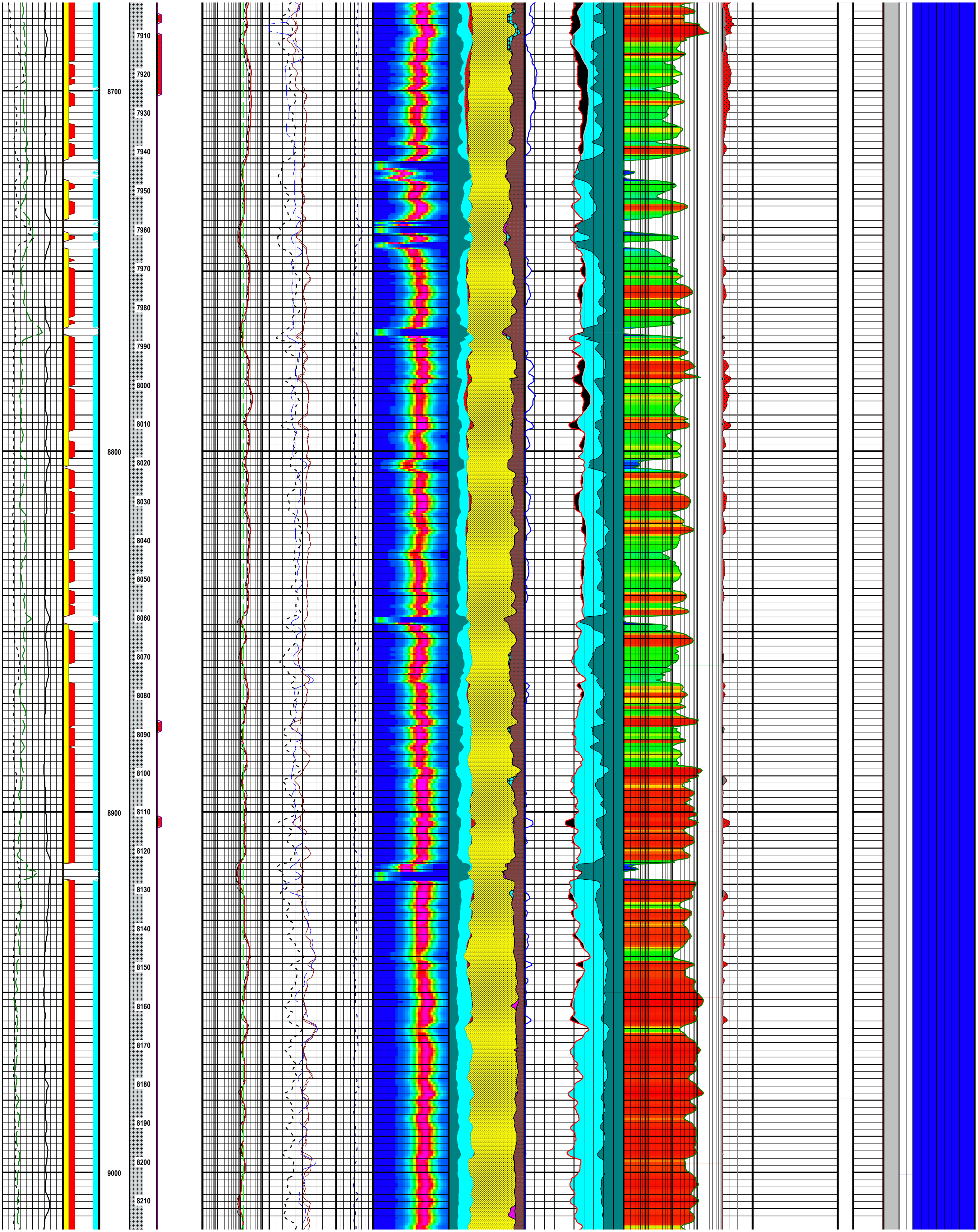
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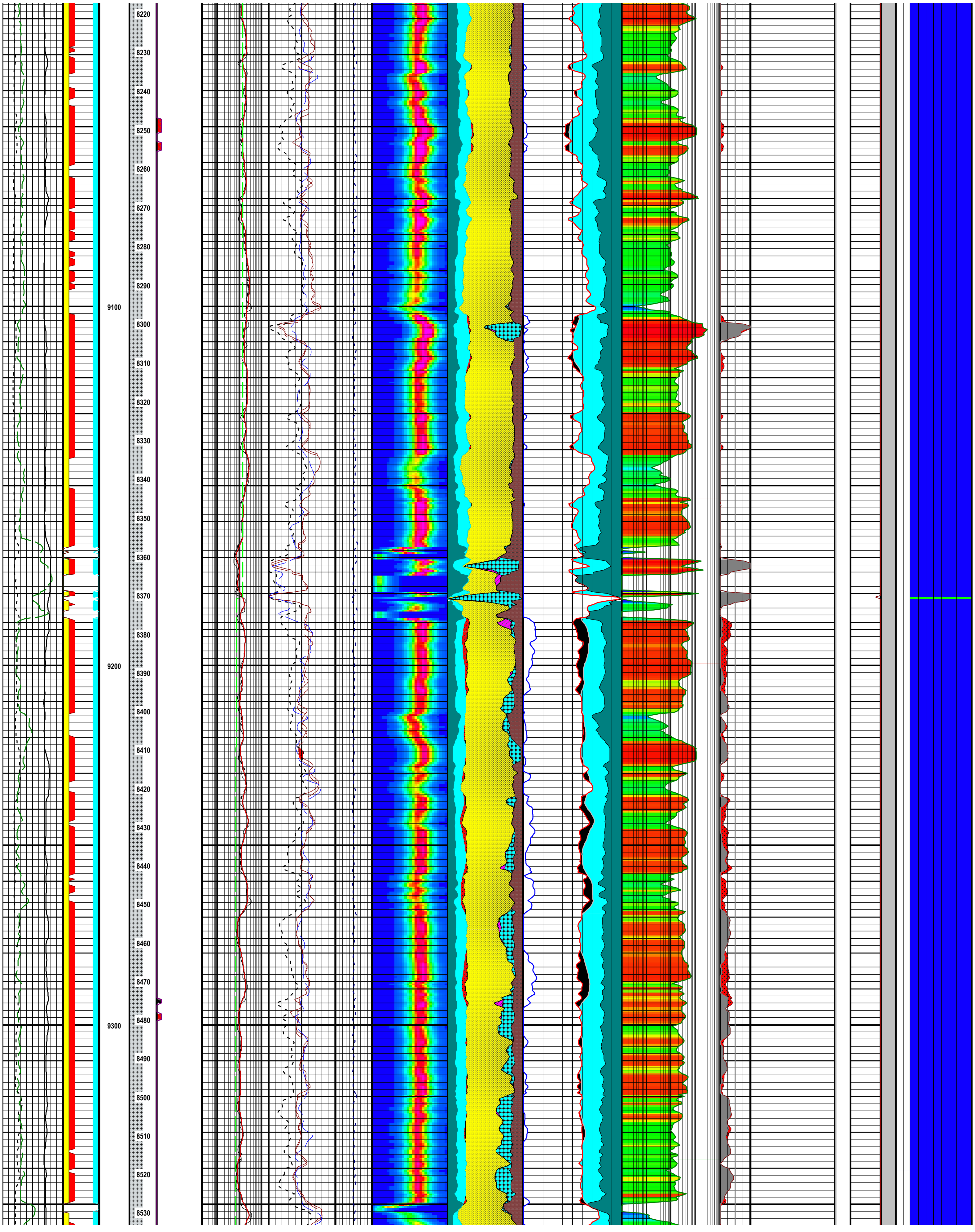
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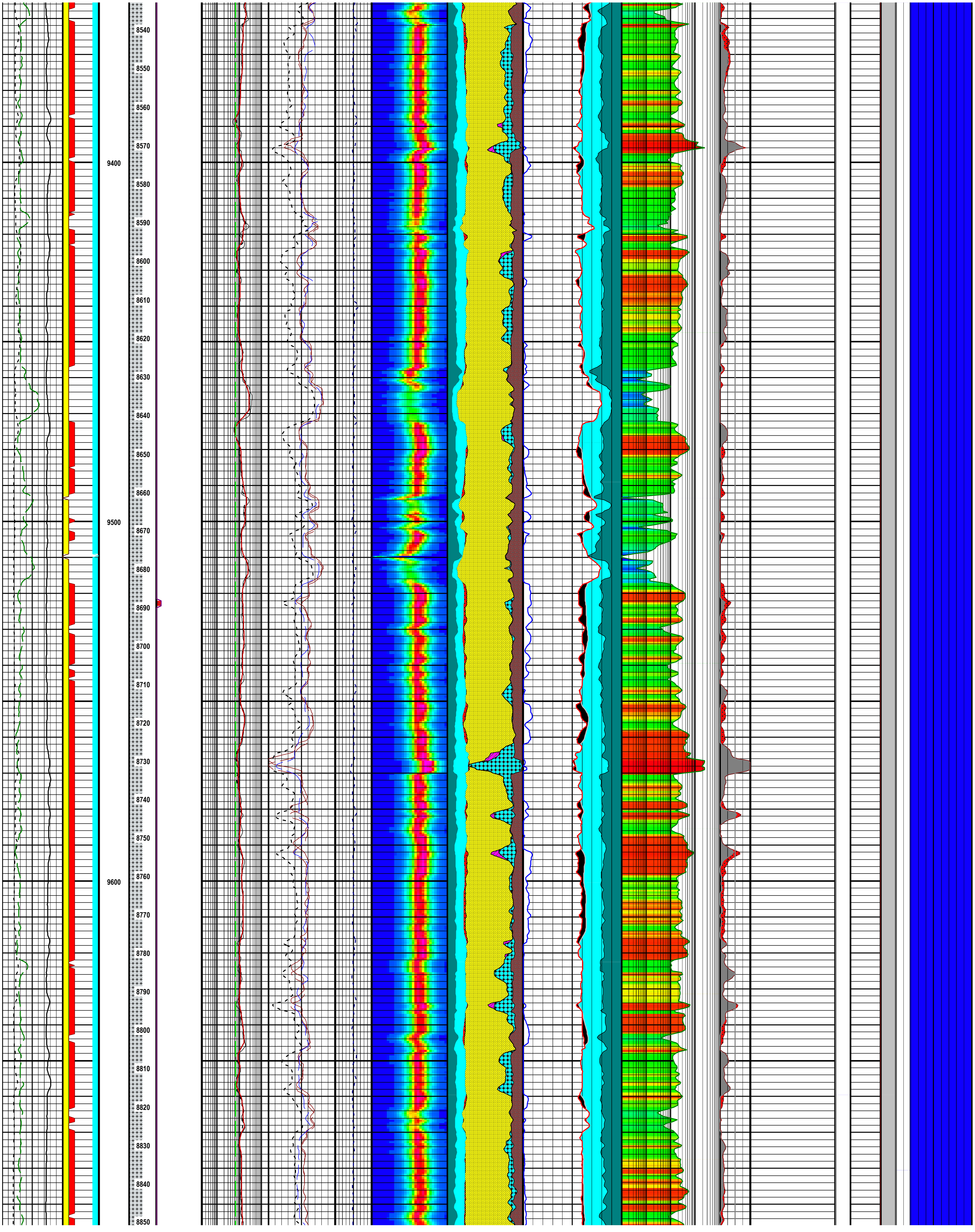
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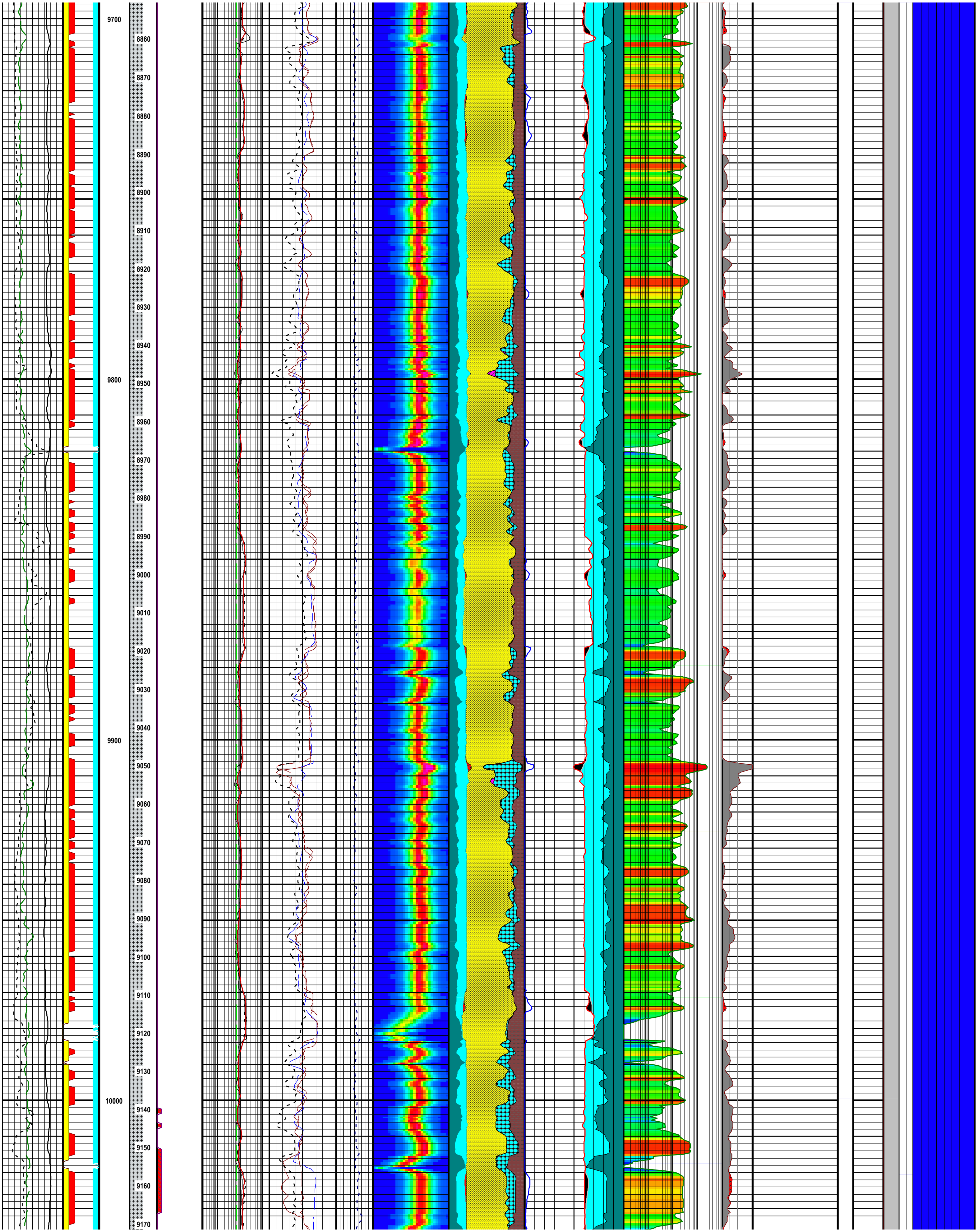
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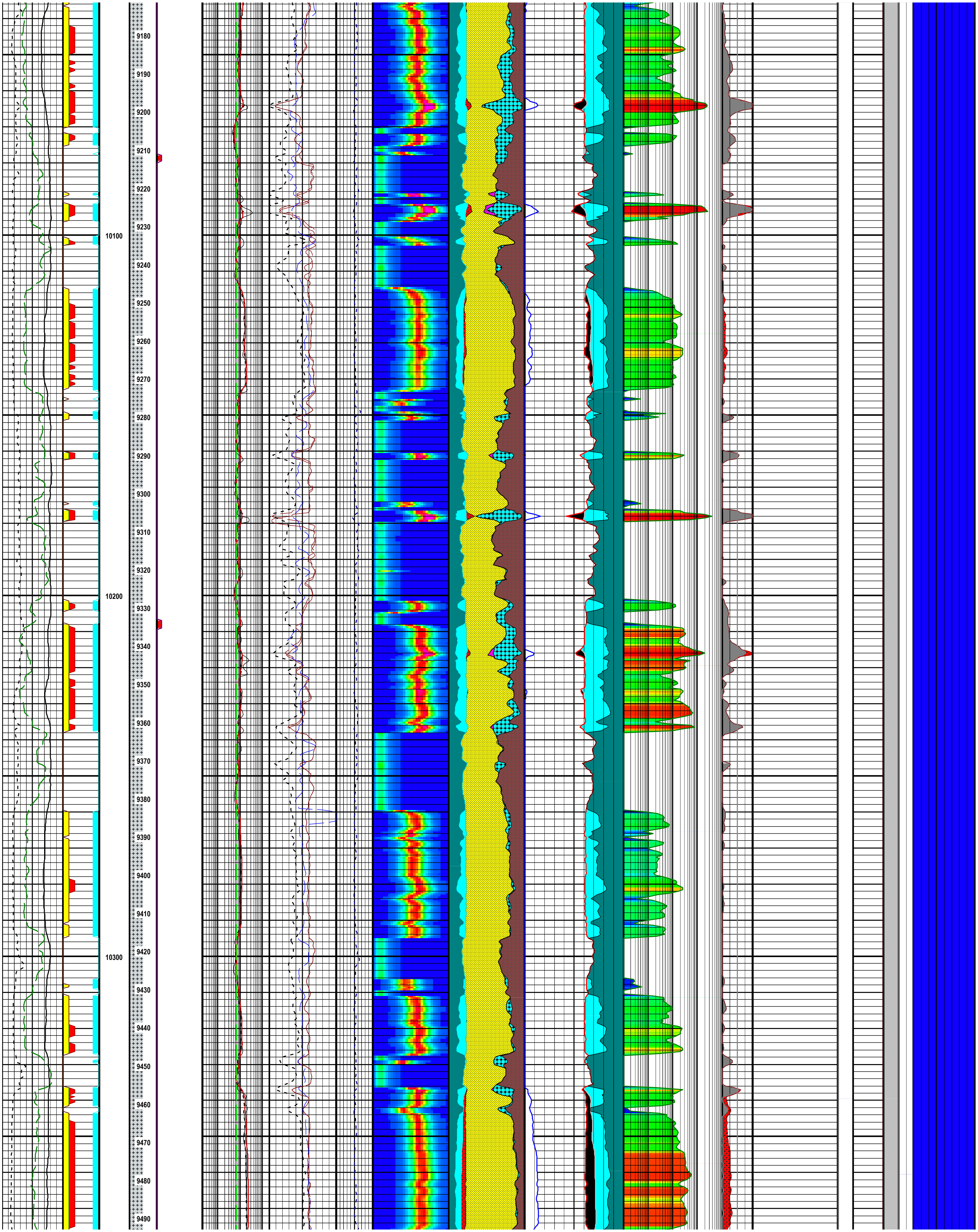
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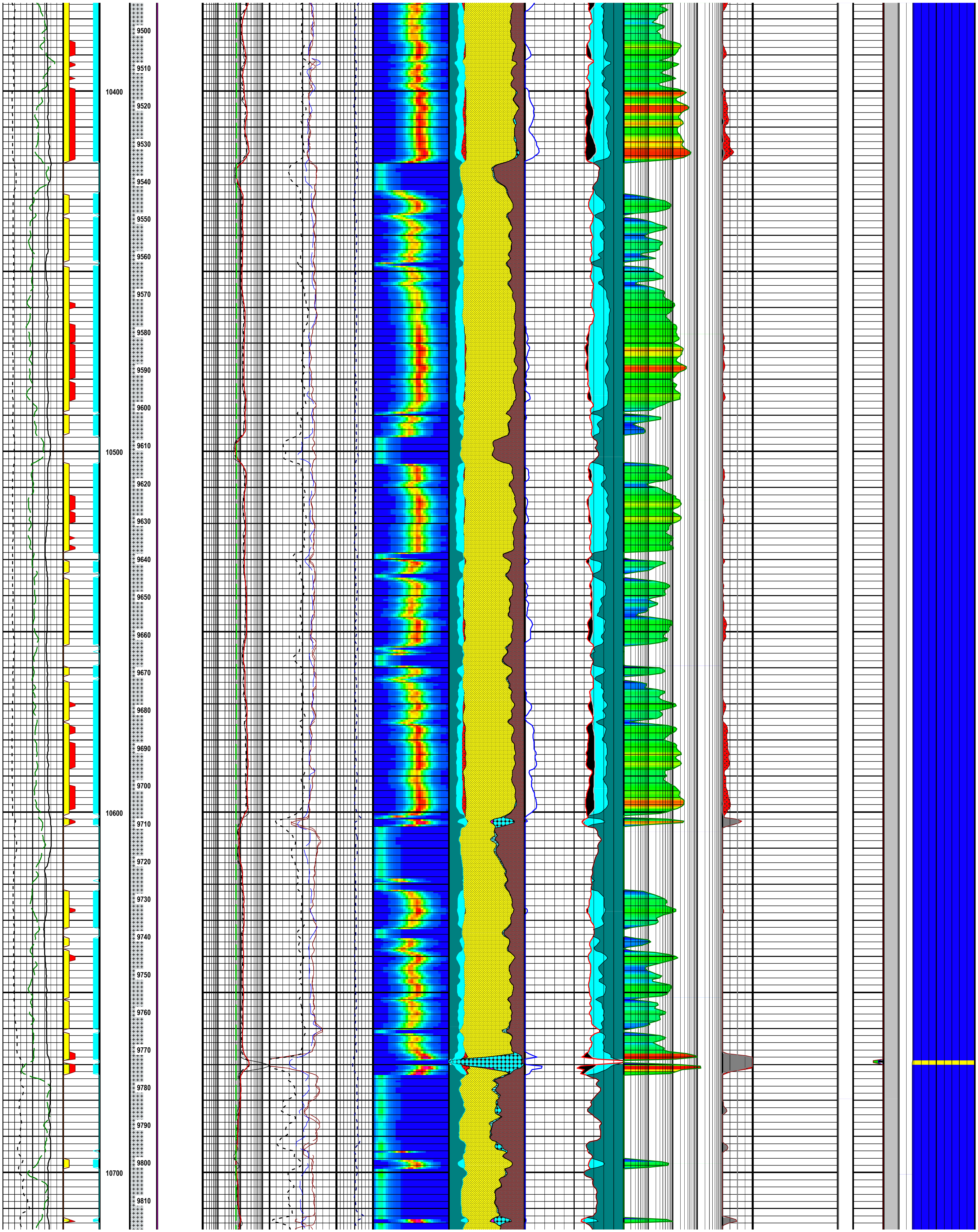
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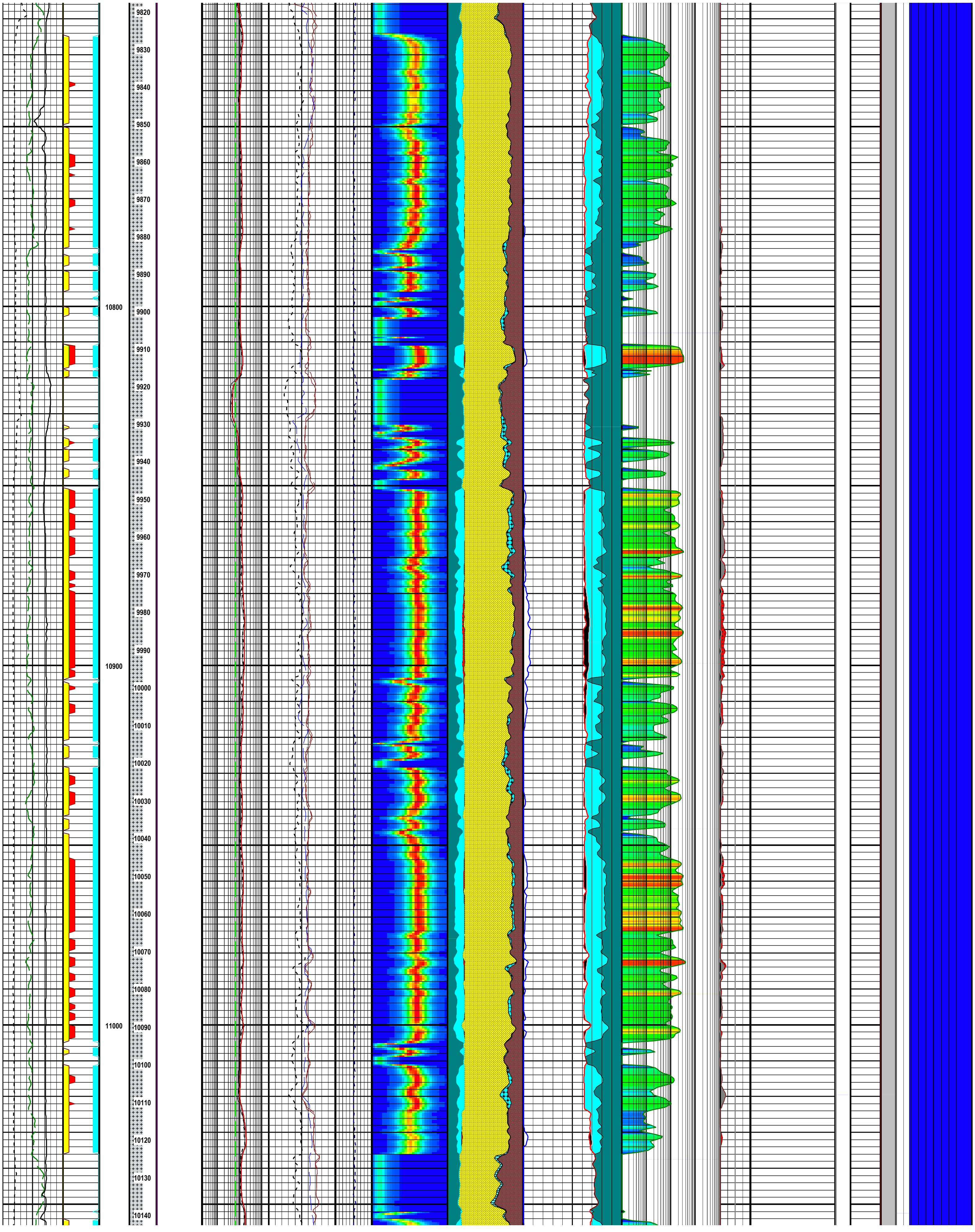
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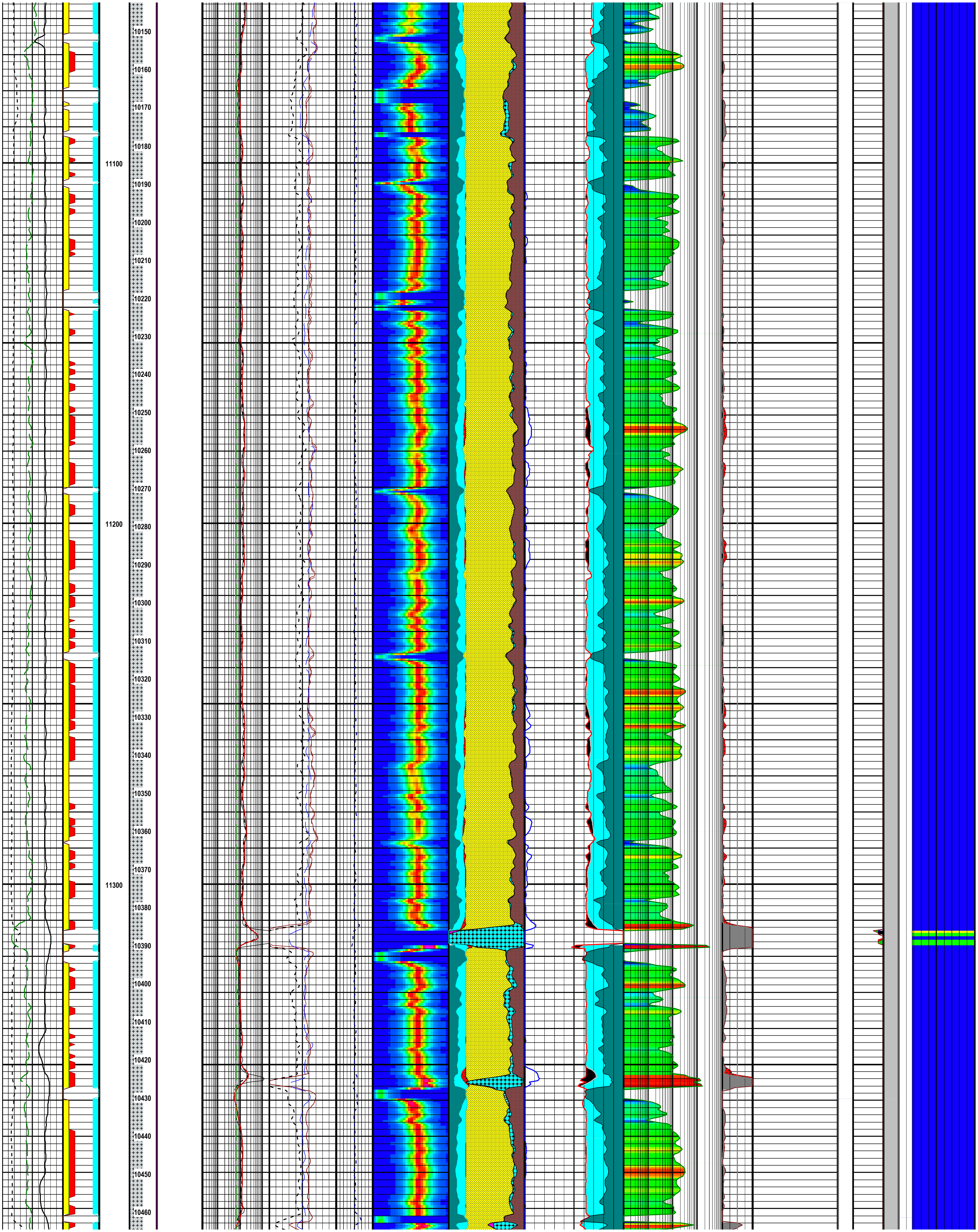
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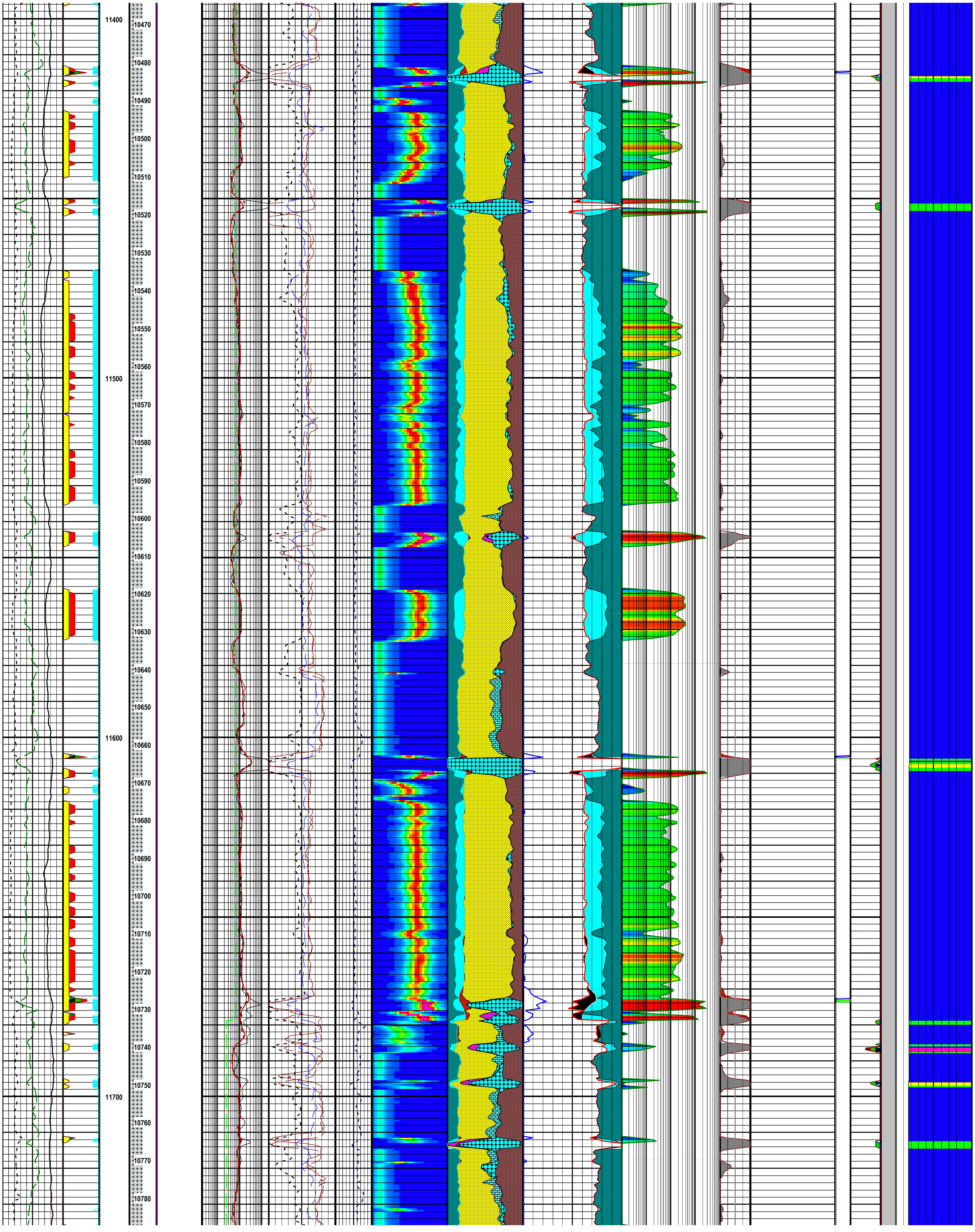
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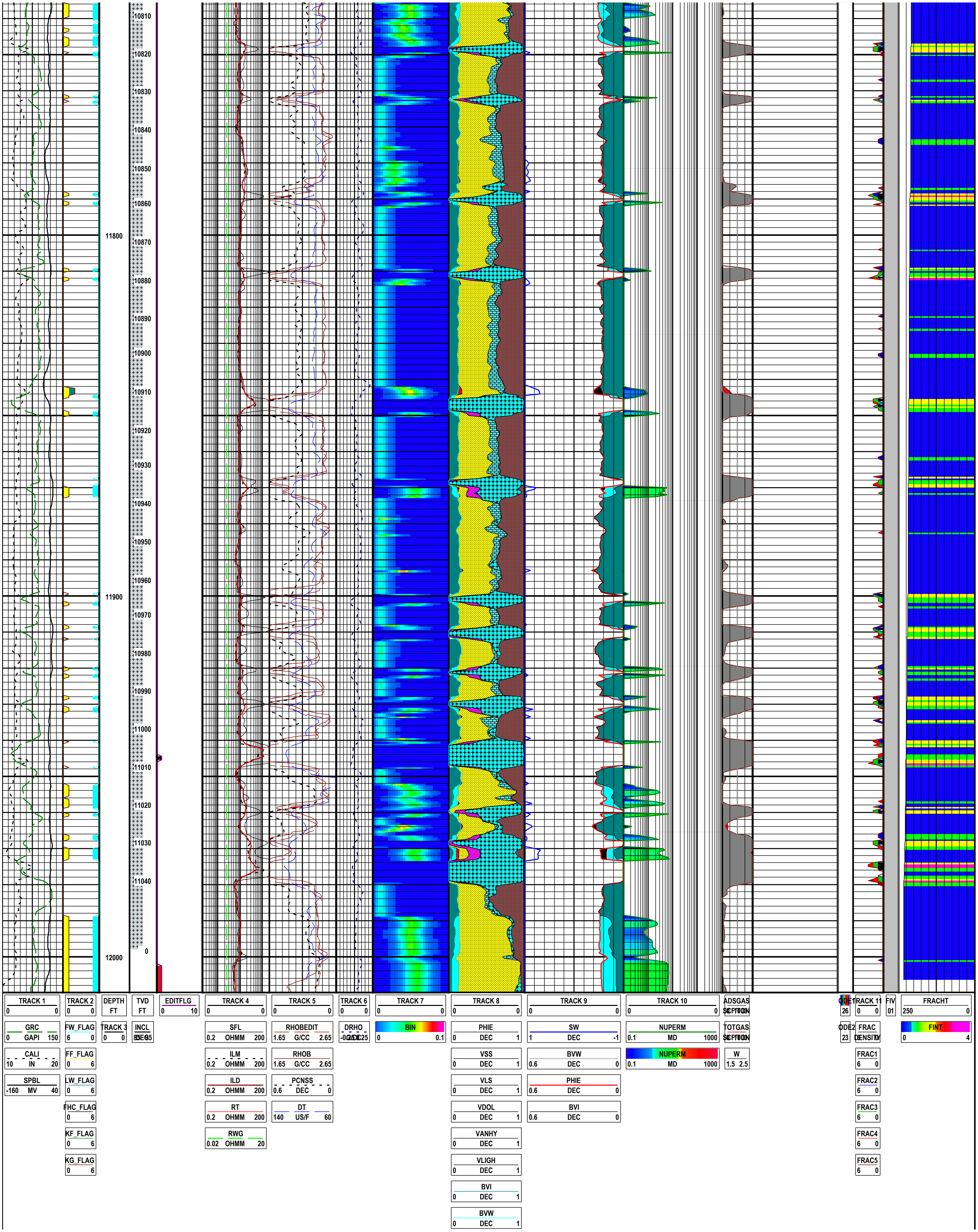
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Client:	Denali Petroleum and Gas Company, LLC
	645 G Street, Ste 732
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Attn:	Frank Avezac

ASRC CONSULTING AND ENVIRONMENTAL SERVICES Project Staff:

Author:	S. Shirzadi
Project Manager:	Doug Cismoski
Quality Control Reviewer:	Doug Cismoski
Technical Editor:	Lori Oswald

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