ESTIMATES
of
RESERVES AND FUTURE REVENUE
and
CONTINGENT AND PROSPECTIVE GAS RESOURCES
attributable to the
PROPOSED TARBA ENERGÍA S.L. INTEREST
in the
EL ROMERAL LICENSE AREA
located in the
GUADALQUIVIR BASIN ONSHORE SOUTHERN SPAIN
as of
JUNE 30, 2019

Prepared for and

BASED ON PRICE AND COST PARAMETERS

specified by

TARBA ENERGÍA S.L.

NETHERLAND, SEWELL & ASSOCIATES, INC.

WORLDWIDE PETROLEUM CONSULTANTS

ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

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October 9, 2019

Mr. Carlos Venturini
Tarba Energía S.L.
Cuesta Sancti Spiritus, 14
Entreplanta, Puerta 1
37001 Salamanca
Spain

Dear Mr. Venturini:

In accordance with your request, we have estimated the proved developed producing, probable, and possible gas reserves and future revenue from the associated generation and sales of electricity, as of June 30, 2019, attributable to the proposed Tarba Energía S.L. (Tarba) interest in El Ciervo-1, Santa Clara-1, and Sevilla-1 Fields in the El Romeral License Area located in the Guadalquivir Basin, onshore southern Spain. Also as requested, we have estimated the unrisked contingent gas resources, as of June 30, 2019, attributable to the proposed Tarba interest in certain contingent areas located updip of the Sevilla-2 and Sevilla-4 gas discoveries in the El Romeral License Area. Additionally, we have estimated the unrisked and risked prospective gas resources, as of June 30, 2019, attributable to the proposed Tarba interest in certain prospects located in the El Romeral License Area. For the purposes of this report, the proposed Tarba interest is the pending acquisition of 100 percent interest in these properties. Tarba is jointly owned by Prospex Oil & Gas plc (Prospex) and Warrego Energy Ltd. (Warrego). We completed our evaluation on or about the date of this letter. For the reserves, this report has been prepared using constant price and cost parameters specified by Tarba, as discussed in subsequent paragraphs of this letter. Monetary values shown in this report are expressed in Euros (€) or thousands of Euros (M€).

The estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) and in accordance with internationally recognized standards, as stipulated by the London Stock Exchange's "Note for Mining and Oil & Gas Companies" dated June 2009 with the exception that the required tables and sensitivity are not included. Definitions are presented immediately following this letter. Following the definitions are the certificates of qualification for the technical persons primarily responsible for preparing the estimates presented in this report and a list of abbreviations used in this report. As presented in the 2018 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

We estimate the gross (100 percent) gas reserves and the future net revenue to the proposed Tarba interest in El Ciervo-1, Santa Clara-1, and Sevilla-1 Fields, as of June 30, 2019, to be:

Category	Gross (100%) Gas Reserves[2] (MMSCM)	Future Net Revenue[1] (M€) Total	Present Worth at 10%
Proved Developed Producing	3.15	(559.3)	(426.8)
Total Proved (1P)	3.15	(559.3)	(426.8)
Probable	5.31	460.4	502.3
Proved + Probable (2P)	8.46	(98.9)	75.5
Possible	3.61	124.9	182.5
Proved + Probable + Possible (3P)	12.07	26.0	257.9

Totals may not add because of rounding.

(1) Future net revenue is from the sale of electricity that is generated from the burning of gas and is net of €860,000 decommissioning costs to be incurred 12 months after the end of the economic field life.
(2) The proposed interest is 100 percent; therefore, net gas reserves to the proposed interest are equal to gross (100 percent) gas reserves.

Gas volumes are expressed in millions of standard cubic meters (MMSCM). The reservoir conditions for standard cubic meters are 15 degrees Celsius (59 degrees Fahrenheit) and 101.325 kilopascals (14.696 pounds per square inch absolute). These properties are not expected to produce commercial volumes of condensate.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. Our study indicates that as of June 30, 2019, there are no proved developed non-producing or proved undeveloped reserves for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk.

The future net revenue shown in this report is not the result of the direct sale of gas but reflects the revenue realized from using the gas to generate electricity. Future net revenue is after deductions for Tarba's share of decommissioning costs, various taxes, and operating expenses but before consideration of any corporate income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using electricity prices based on electricity sales and revenue records from January 2017 through April 2019 provided by Tarba. Revenue from the sale of electricity includes both the electricity price of €0.06 per kilowatt-hour and the government cogeneration facility subsidy of €0.02 per kilowatt-hour. All prices are held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of Petroleum Oil & Gas España SA (POGESA), a subsidiary of Naturgy Energy Group S.A. and the operator of the properties in 2017 and 2018, as provided by Tarba. These costs include the costs to operate the wells and the associated facilities used for both the production of gas and the generation of electricity for sales. For all properties, headquarters general and administrative overhead expenses of Tarba are not included. As requested, operating costs are not escalated for inflation.

Decommissioning costs used in this report are POGESA's estimates of the costs to abandon the wells and pipelines and restore the industrial lands and well sites and were provided by Tarba. As requested, decommissioning costs are not escalated for inflation.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. The contingent resources shown in this report are contingent upon (1) extension of the concession life, (2) increase of production rate limitations, (3) acquisition of additional technical data that demonstrate sufficient producing rates and volumes to sustain economic viability, (4) acquisition of data that confirm continuity of the reservoirs, (5) further appraisal drilling to confirm development potential, and (6) commitment to develop the resources. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed. We did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

We estimate the discovered original gas-in-place (OGIP) and the unrisked gross (100 percent) contingent gas resources for these contingent areas, as of June 30, 2019, to be:

	Discovered OGIP (MMSCM)			Unrisked Gross (100%) Contingent Gas Resources (MMSCM)		
Contingent Area	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Romeral-4 Sur	72.6	111.5	157.8	57.7	93.1	138.8
Tarazona	38.9	59.8	85.9	30.0	48.9	74.5
Total[1]	111.5	171.3	243.7	87.7	142.0	213.3

Note: The Romeral-4 Sur and Tarazona Contingent Areas are updip of two subcommercial discoveries, the Sevilla-2 and Sevilla-4 wells, respectively. Both discovery wells had gas above formation water with the potential for development at a higher structural elevation.

[1] Totals are the arithmetic sum of multiple probability distributions.

As requested, the scope of this project for the contingent resources includes only gas resources. In-place volumes are reported at surface conditions.

The contingent resources shown in this report have been estimated using a combination of deterministic and probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk. As recommended in the PRMS, the 1C, 2C, and 3C reserves have been aggregated beyond the field level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. Because of the early stage of development of this project, we did not perform an economic analysis on these resources; as such, the economic status of these resources is undetermined.

The undiscovered accumulations assessed in this report have been subclassified as prospects. The 2018 PRMS defines a prospect as a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target, a lead as a project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be subclassified as a prospect, and a play as a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the undiscovered OGIP, the unrisked and risked gross (100 percent) prospective gas resources, and the probability of geologic success (P_g) for these prospects, as of June 30, 2019, to be:

				Gross (100%) Prospective Gas Resources (MMSCM)						
	Undiscovered OGIP (MMSCM)			Unrisked			Risked			
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	P_g
Aventurado Norte	519.1	842.5	1,256.7	415.2	707.2	1,109.5	311.4	530.4	832.1	0.75
Aventurado Sur	447.6	717.5	1,060.1	341.4	580.9	913.0	256.0	435.7	684.7	0.75
Cervatillo	42.2	64.4	92.1	31.1	50.8	77.8	25.2	41.1	63.0	0.81
Gamo	62.7	100.4	147.6	46.3	79.3	125.0	39.4	67.4	106.3	0.85
Rio Corbones Oeste (Uceda)	58.7	115.2	199.4	39.9	85.6	162.1	33.9	72.7	137.8	0.85
Romeral-1 Sand 1	147.9	315.1	594.3	117.5	263.1	522.7	105.7	236.8	470.4	0.90
Romeral-1 Sand 2	21.4	84.5	246.3	17.0	70.5	216.6	8.5	35.3	108.3	0.50
Romeral-2 Sur Sand	170.5	320.1	531.0	128.8	257.3	455.1	104.4	208.4	368.6	0.81
Romeral-2 Upper Sand	24.8	50.2	93.2	18.7	40.4	79.9	13.1	28.2	55.9	0.70
Romeral-3	63.6	114.2	185.4	43.3	85.0	150.9	35.1	68.8	122.2	0.81
Saltillo	109.5	216.8	374.0	86.6	180.4	328.2	70.2	146.2	265.9	0.81
San Pablo	30.2	46.0	65.2	23.9	38.4	57.4	18.0	28.8	43.0	0.75
Santiche	74.2	122.1	181.9	59.4	102.5	160.6	41.6	71.8	112.4	0.70
Total(1)	1,772.5	3,109.0	5,027.1	1,369.2	2,541.3	4,358.8	1,062.4	1,971.5	3,370.8	

(1) Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

As requested, the scope of this project for the prospective resources includes only gas resources. In-place volumes are reported at surface conditions.

The prospective resources shown in this report have been estimated using a combination of deterministic and probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of prospective resources are referred to as 1U, 2U, and 3U, respectively. As recommended in the PRMS, the 1U, 2U, and 3U reserves have been aggregated beyond the field level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements for each prospect.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects.

GENERAL INFORMATION

As shown in the Table of Contents, this report contains a technical discussion and pertinent figures. The Technical Discussion section of this report includes an overview of the El Romeral License Area, a review of the data available for this evaluation, and a discussion of the technical approach used in our reserves and resources evaluation.

This report does not include any value that could be attributed to interests in undeveloped acreage. For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Based on the information used in our analysis, it is our opinion that a field visit was not required and would not materially affect our evaluation. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves, contingent resources, and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Tarba, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 PRMS definitions and guidelines. The contingent and prospective resources shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

This report on certain properties located in the Guadalquivir Basin, onshore southern Spain, was prepared by qualified technical persons of Netherland, Sewell & Associates, Inc. (NSAI). Following the definitions are the certificates of qualification for the technical persons primarily responsible for preparing the estimates presented in this report. This report has been prepared at the request of Tarba for the benefit of its shareholders Prospex and Warrego, both of whom are quoted companies. Prospex is quoted on the AIM section of the London Stock Exchange, and Warrego is quoted on the Australian Securities Exchange.

NSAI was established in 1961 and has offices located in Dallas and Houston, Texas, United States of America. NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. NSAI is professionally qualified and a member in good standing of an appropriate, recognized professional association under the AIM Rules for Companies with at least 5 years of relevant experience in the estimation, assessment, and evaluation of oil and gas. We provide a complete range of geological, geophysical, and engineering services, and we have the technical expertise and ability to perform these services in any oil and gas producing area in the world. Our company has conducted technical reserves, resources, and deliverability studies for financial institutions, private and government companies, and government agencies throughout the world. The staff are familiar with the recognized industry reserves and resources definitions, specifically those promulgated by the U.S. Securities and Exchange Commission, by the Alberta Securities Commission, and by the SPE, Society of Petroleum Evaluation Engineers, World Petroleum Council, and American

Association of Petroleum Geologists. Our staff and associates work as a team to provide the integrated expertise required for complex field studies and for evaluations involving reserves, contingent resources, and prospective resources. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; with the exception of the provision of professional services on a fee basis, NSAI has no commercial arrangement with any person or company involved with Tarba. Our fee for this evaluation and report is not contingent on the results obtained and reported, and NSAI will receive no other benefit for the preparation of this report. We have not performed any other work that might affect our objectivity. Neither NSAI nor any of its directors, officers, employees, or subconsultants has any pecuniary or other interests in Tarba or its properties or any related companies. We hereby assert that we have not been made aware of any material change in the data used in this evaluation that would cause us to materially alter the estimates set forth herein.

The data used in our estimates were obtained from Tarba, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By:
Gregory S. Cohen, P.E. 117412
Vice President

STATE OF TEXAS
G. S. COHEN
117412
LICENSED
PROFESSIONAL ENGINEER

Date Signed: October 9, 2019

By:
Daniel T. Walker, P.G 1272
Senior Vice President

STATE OF TEXAS
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GEOLOGY
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Date Signed: October 9, 2019

DTW:AJK

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_c, which is the chance that a project will be committed for development and reach commercial producing status.

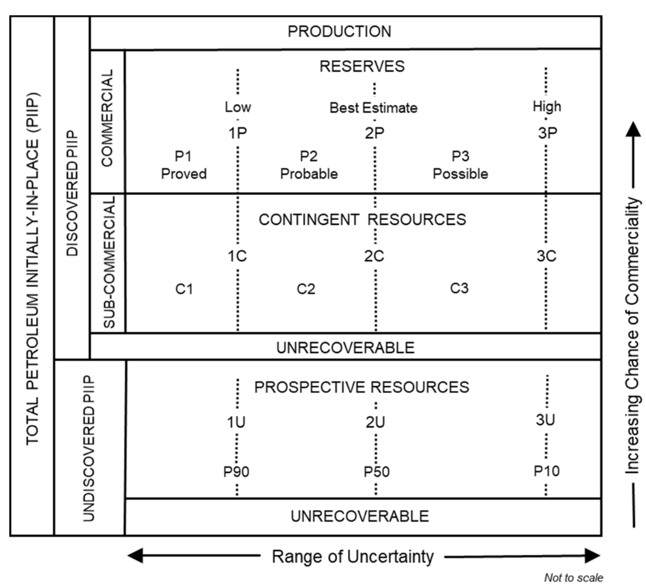

Figure 1.1—Resources classification framework

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, June 2018

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

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1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

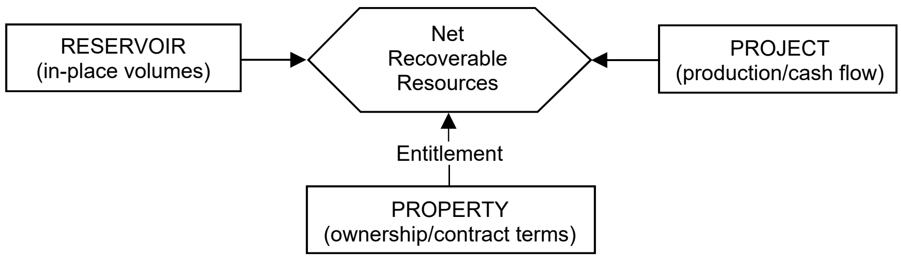

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

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1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3), 1C, 2C, 3C, C1, C2, and C3; or 1U, 2U, and 3U resources categories. The commercial chance of success is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

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2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

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Class/Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

CERTIFICATE OF QUALIFICATION

I, Daniel T. Walker, Licensed Professional Geoscientist, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, United States of America (U.S.A.), hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain gas properties to the proposed Tarba Energía S.L. (Tarba) interest. The effective date of this evaluation is June 30, 2019.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Tarba or its affiliated companies.

I attended Michigan State University and graduated in 1980 with a Bachelor of Science Degree in Geology; I am a Licensed Professional Geoscientist in the State of Texas, U.S.A.; and I have in excess of 39 years of experience in geological and geophysical studies and evaluations.

A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information or records, the files from Tarba, and the appropriate provincial regulatory authorities.

/s/ Daniel T. Walker

By: ____

Daniel T. Walker, P.G.
Senior Vice President
Texas Registration No. 1272

October 9, 2019
Dallas, Texas
U.S.A.

NETHERLAND, SEWELL & ASSOCIATES, INC.

CERTIFICATE OF QUALIFICATION

I, Gregory S. Cohen, Licensed Professional Engineer, 2100 Ross Avenue, Suite 2200, Dallas, Texas 75201, United States of America (U.S.A.), hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties to the proposed Tarba Energía S.L. (Tarba) interest. The effective date of this evaluation is June 30, 2019.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Tarba or its affiliated companies.

I attended Carnegie Mellon University and graduated in 1980 with a Bachelor of Science Degree in Chemical Engineering; I attended Anderson Graduate School of Management at University of California Los Angeles and graduated in 1993 with a Master in Business Administration; I am a Licensed Professional Engineer in the State of Texas, U.S.A.; and I have in excess of 20 years of experience in petroleum engineering studies and evaluations.

A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information or records, the files from Tarba, and the appropriate provincial regulatory authorities.

By: /s/ Gregory S. Cohen
Gregory S. Cohen, P.E.
Vice President
Texas Registration No. 117412

October 9, 2019
Dallas, Texas
U.S.A.

ABBREVIATIONS

€	Euros
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
1U	low estimate scenario of prospective resources
2U	best estimate scenario of prospective resources
3U	high estimate scenario of prospective resources
AVO	amplitude variation with offset
B_g	gas formation volume factor
Chevron	Chevron Corporation
DHI	direct hydrocarbon indicator
ft	feet
GWC	gas-water contact
km	kilometers
km^2	square kilometers
m	meters
M€	thousands of Euros
Max	maximum
MCF/ac-ft	thousands of cubic feet per acre-foot
MD	measured depth
Min	minimum
ML	most likely
MMSCM	millions of standard cubic meters
MSCM	thousands of standard cubic meters
NSAI	Netherland, Sewell & Associates, Inc.
NTG	net-to-gross ratio
OGIP	original gas-in-place
P/Z	pressure decline curve
P10	10 percent confidence level
P5	5 percent confidence level
P50	50 percent confidence level
P90	90 percent confidence level

ABBREVIATIONS

P95	95 percent confidence level
P_g	probability of geologic success
POGESA	Petroleum Oil & Gas España SA
PRMS	Petroleum Resources Management System
Prospex	Prospex Oil & Gas plc
S_g	gas saturation
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
S_w	water saturation
Tarba	Tarba Energía S.L.
TWT	two-way travel time
U.S.A.	United States of America
Warrego	Warrego Energy Ltd.

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NETHERLAND, SEWELL & ASSOCIATES, INC.

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TECHNICAL DISCUSSION

TECHNICAL DISCUSSION
EL ROMERAL LICENSE AREA, ONSHORE SOUTHERN SPAIN

1.0 OVERVIEW

The El Romeral License Area is located in the Guadalquivir Basin, onshore southern Spain. The license area is subdivided into three contiguous blocks, the El Romeral-1, El Romeral-2, and El Romeral-3 License Blocks, and covers an area of approximately 310 square kilometers (km^2) (76,603 acres), as shown on Figure 1. Our evaluation of the El Romeral License Area in this study consists of (1) analysis and review of historical well production performance and lease operating statements provided by Tarba Energía S.L. (Tarba); (2) previous prospective resources assessments of the El Romeral License Area conducted by Netherland, Sewell & Associates, Inc. (NSAI) from 1999 to 2005 with data provided by Petroleum Oil & Gas España SA (POGESA); (3) estimation of gas reserves for three mature producing gas wells; (4) estimation of unrisked contingent gas resources for connected reservoirs located at shallower elevations updip from two subcommercial gas discoveries; and (5) estimation of undiscovered original gas-in-place (OGIP) and unrisked and risked prospective gas resources for 13 identified prospects. Monetary values shown in this report are expressed in Euros (€) or thousands of Euros (M€).

Between 1999 and 2005, NSAI evaluated the gas reserves and prospective gas resources potential of the El Romeral License Area on behalf of the previous license operator, POGESA. Updates in this report include our most recent production forecasts of ultimate recovery from three producing wells. Our contingent and prospective gas resources estimates have been updated to incorporate revised formation volume factor analysis. Also, for this report the connected reservoir areas at a shallower elevation from the subcommercial gas discoveries in the Sevilla-2 and Sevilla-4 wells are classified as contingent resources. The contingent resources shown in this report have been estimated using a combination of deterministic and probabilistic methods. Once all contingencies have been successfully addressed, the probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The prospective resources shown in this report have been estimated using a combination of deterministic and probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of prospective resources are referred to as 1U, 2U, and 3U, respectively. A summary of Monte Carlo input parameters used for estimation of contingent and prospective gas resources is included on Figure 2.

As requested, we did not conduct an economic analysis of drilling costs, completion and tie-in costs, compression costs, or operating costs to determine threshold prospective gas resources for development. For the purposes of this report, we did not evaluate or estimate costs associated with seismic data acquisition nor did we take into account environmental or political considerations.

1.1 OWNERSHIP AND LICENSE TERMS

Under the Asset Purchase Agreement, the licenses that constitute the El Romeral License Area, along with associated production and electric generation equipment, are to be transferred from the current owner, POGESA, to Tarba. POGESA will remain as the operator until the transfer to Tarba is approved by the Ministry for the Ecological Transition. POGESA is a subsidiary of Naturgy Energy Group S.A. Tarba is owned by Warrego Energy Ltd. and Prospex Oil & Gas plc. At the time of writing, the purchase of the licenses will be funded by the issuance of B shares to Tarba's two shareholders at a ratio to be determined postacquisition.

In 2006, at the time of acquiring the asset, POGESA agreed to a 16 percent gross overriding royalty interest over the exploration opportunities in the licenses. None of the current production is subject to the gross overriding royalty interest but exploration opportunities in the El Romeral License Area are. The former sellers are entitled to financial payments equivalent to 16 percent of revenues from future gas sales derived from future exploration.

The first validity period of the El Romeral License Area is set to end in 2024, with a provision to extend such validity for two further 10-year periods. Tarba currently meets the legal requisites of keeping the concessions in operation and in full compliance with its legal obligations."

Portions of certain prospective reservoirs evaluated herein are located immediately south of the current El Romeral License Area. Under the Asset Purchase Agreement, efforts are in progress to permit the adjoining areas and transfer them to Tarba. This will allow Tarba to optimize drilling locations to test the prospective reservoirs.

1.2 EXPLORATION AND DEVELOPMENT SUMMARY

Exploration in the El Romeral License Area began in the 1950s when the Carmona-1, Carmona-2, Carmona-3, Carmona-4, and Carmona-5 wells were drilled in the northeast region of the license area. These wells were dry holes. During the 1980s, Chevron Corporation (Chevron) acquired a grid of 2-D seismic lines and processed the data to evaluate amplitude variation with offset (AVO). This processing provided direct hydrocarbon indicators (DHIs) for identifying the presence of gas-bearing reservoirs and led to the drilling of three successful discoveries (El Ciervo-1, Sevilla-1, and Sevilla-3) and two subcommercial gas wells (Sevilla-2 and Sevilla-4) on the El Romeral License Area by Chevron. The two subcommercial wells, drilled on the basis of DHIs, encountered minor gas volumes above formation water and were not completed. Repsol S.A. acquired the license area in 1994 and in 1998 drilled the Santa Clara-1 gas discovery well. Through a series of transactions from 2002 to 2005, POGESA acquired a 79 percent interest in the license area, and by 2008 it owned a 100 percent interest. POGESA drilled the successful Rio Corbones-1 discovery well in 2007. A summary of the gas discovery wells and subcommercial gas wells is shown on the following table:

Well	Operator	Year Drilled	Result
El Ciervo-1	Chevron	1983	Gas Discovery
Sevilla-1	Chevron	1984	Gas Discovery
Sevilla-2	Chevron	1985	Subcommercial Gas
Sevilla-3	Chevron	1985	Gas Discovery
Sevilla-4	Chevron	1989	Subcommercial Gas
Santa Clara-1	Repsol S.A.	1998	Gas Discovery
Rio Corbones-1	POGESA	2007	Gas Discovery

During 2002, the El Ciervo-1, Santa Clara-1, Sevilla-1, and Sevilla-3 wells were brought online to produce gas to a nearby gas plant for electricity generation. The Rio Corbones-1 well produced gas from 2012 to 2017 and is currently shut-in because of formation water influx. Sevilla-3 is also currently shut-in because of water influx. The remaining three wells, El Ciervo-1, Santa Clara-1, and Sevilla-1, currently produce an average of 214 thousand standard cubic meters (MSCM) per month. Well status, cumulative production, and May 2019 production are shown in the following table:

Well Name	Production History	Status	Cumulative Production (MSCM)	May 2019 Production (MSCM)
El Ciervo-1	2002-Current	Producing	107,297	98
Santa Clara-1	2002-Current	Producing	31,213	19
Sevilla-1	2002-Current	Producing	15,605	96
Sevilla-3	2002-2008	Shut-in; water inflow 2008	22,391	0
Rio Corbones-1	2012-2017	Shut-in; early water breakthrough	8,084	0

The volumes currently being produced are not sold but used in an electric power generation plant for the generation and sales of electricity. The plant is only operated when electricity can be sold for a high price. Over the course of the last 12 months, electricity sales occurred 78 percent of the time.

1.3 FUTURE PRODUCTION

All three of the gas production wells are producing at low rates, and all have seen a recent reservoir pressure increase when wells were shut-in or produced at very low rates. At this late stage of depletion, there is insufficient reservoir volumetric accuracy or diagnostic information available to determine if the pressure indicates either an influx of water or low-permeability gas bleeding into the reservoirs.

We evaluated a production model that provided an estimate of the remaining economically producible gas based on gas feeding in from low-permeability rock for the El Ciervo-1 and Santa Clara-1 with water influx for the Sevilla-1. The results of this model provided a 3P estimate (55-month scenario). Reserves would decrease if water support accounted for the El Ciervo-1 or Santa Clara-1 pressure increase. If the water reached a well, it would possibly cease flowing (12-month scenario).

The 1P estimate was based on a 12-month producing life from this report's as-of date. This 1P estimate represents a scenario where the pressure support is due to water influx, and water movement to a well causes the field production to either cease or fall below an economic rate. The 2P scenario is at the midpoint of the 1P (12-month) and 3P (55-month) scenarios.

1.4 FUTURE REVENUE BASIS

Future revenue for the producing wells was derived from electricity sales. Operating costs are based on operating expense records of POGESA, the operator of the properties in 2017 and 2018, as provided by Tarba. As requested, future costs of €860,000 are included for decommissioning of the wells and pipelines and restoration of the industrial lands and well sites. Decommissioning costs are POGESA's estimates and were provided by Tarba.

1.5 GAS RESERVES AND FUTURE NET REVENUE

We estimate the gross (100 percent) gas reserves and future net revenue to the proposed Tarba interest in El Ciervo-1, Santa Clara-1, and Sevilla-1 Fields, as of June 30, 2019, to be:

Category	Gross (100%) Gas Reserves(2) (MMSCM)	Future Net Revenue(1) (M€) Total	Present Worth at 10%
Proved Developed Producing	3.15	(559.3)	(426.8)
Total Proved (1P)	3.15	(559.3)	(426.8)
Probable	5.31	460.4	502.3
Proved + Probable (2P)	8.46	(98.9)	75.5
Possible	3.61	124.9	182.5
Proved + Probable + Possible (3P)	12.07	26.0	257.9

Totals may not add because of rounding.

(1) Future net revenue is from the sale of electricity that is generated from the burning of gas and is net of €860,000 decommissioning costs to be incurred 12 months after the end of the economic field life.
(2) The proposed interest is 100 percent; therefore, net gas reserves to the proposed interest are equal to gross (100 percent) gas reserves.

Gas volumes are expressed in millions of standard cubic meters (MMSCM). The reservoir conditions for standard cubic meters are 15 degrees Celsius (59 degrees Fahrenheit) and 101.325 kilopascals (14.696 pounds per square inch absolute).

2.0 GEOLOGIC OVERVIEW

The Guadalquivir Basin has a complex history beginning with continental rifting, extension, and basin subsidence during the Mesozoic Era followed by development of a foreland basin related to the convergence of Eurasia and Africa during the Tertiary Period. The basin is bounded to the south by the Betic Cordillera and an olistostrome front formed by north-verging thrust faults (Figure 3). The basin is bounded to the north by the Sierra Morena range. During the Miocene Epoch, turbidite sediments were deposited into the foreland basin, backfilling a series of basin-floor incised valleys and channels. The levee channel systems are oriented northeast to southwest approximately parallel to the Betic Orogeny. During basin downwarping and subsidence, the channel sequences migrated to the north, resulting in a series of overlapping channel fill and levee deposits that form combination structural-stratigraphic traps for the discovered fields and contingent and prospective areas. The turbidite channel trends are truncated to the north by a deep and elongated erosional submarine canyon of Pliocene age that is predominantly filled with argillaceous sediments of the Sevilla Group.

Confined channel and debris flow deposits occur in the proximal shelf areas with progressive downslope deposition occurring in a combination of weakly to moderately confined channels, channel overbank splays and lobes, or distributary slope fans (Figure 4). The El Romeral License Area is located in the upper to middle slope regions where sediment deposition is largely trapped within confined channel complexes. These confined channels may extend over several kilometers (km) from northeast to southwest along the predominant sediment transport direction and have a range of north-to-south channel widths of 300 to 1,000 meters (m) (984 to 3,281 feet [ft]). The transition from confined channels to less-confined meandering and amalgamated channel facies is interpreted to occur near the southwest portion of the El Romeral-1 License Block and extends to the southwest across the basin.

The vertical succession of valley fill that may occur within a single incised valley is illustrated on Figure 5. As the incised valley is progressively backfilled by channel, associated channel, overbank levee, and splay deposits, earlier deposited sediments may undergo significant reworking, preserving only remnants of previous deposits. Therefore, the middle to late stages of valley infilling are more likely to have preserved sedimentary sequences than the earlier base of channel deposits. Channel system migration within an incised valley can, however, result in vertically stacked channel and marginal channel sequences that, when gas-charged, provide dual drilling objectives. Within the Guadalquivir Basin, the process of valley incision has occurred multiple times, with older incised valleys being partially incised by progressively younger incised valleys, as shown on Figure 5.

The incised valley channel systems are generally oriented in a northeast-southwest direction and are progressively deeper from northeast to southwest, ranging from 314 to 1,206 m measured depth (MD) (1,030 to 3,957 ft MD) across the El Romeral License Area. Fields have generally been developed and produced through a single well. The trapping mechanism is a combination of structural and stratigraphic closure along valley wall incisions, erosional truncation by the overlying predominantly shale-filled submarine canyon, and stratigraphic pinchout. Most productive reservoirs are low relief with structural dip of less than 2 degrees. Trap closures of productive reservoirs are estimated from the seismic AVO data to generally cover less than 2.0 km^2 (494 acres). Connected AVO response on adjoining seismic dip lines can be interpreted as continuous channels with prospective closure areas ranging from 1.0 to 48.0 km^2 (247 to 11,861 acres).

Average net reservoir thickness, including all gas and water-wet intervals, is 7 m and varies from 1 to 33 m. Reservoir quality is highly variable, ranging from well-sorted medium- to coarse-grained sandstones with low clay content to poorly sorted fine-grained sandstones, siltstones, and clay. Average reservoir porosity and gas saturation (S_g) are 30 and 55 percent, respectively. Pressure depletion is the primary reservoir drive mechanism, although gas-water contacts (GWCs) are detected from well logs over certain reservoir intervals and early to late water influx is recorded in certain wells.

3.0 DATA SOURCES

Data used in this report include a grid of 2-D seismic lines of various vintages ranging from 1980 to 2002, well logs, limited core data, and production and well test data. The seismic data provide indications of prospect area, prospective gross interval thickness, and hydrocarbon gas presence. Interpreted well log and core data provide an analog of prospective reservoir characteristics including reservoir facies, gross and net reservoir thickness, porosity, and water saturation (S_w). Production data provide gas composition, pressure, and temperature data for estimating gas formation volume factors (B_gs). Performance and P/Z analysis of mature producing wells provide analog data of in-place and recoverable gas volumes for the developed field reservoirs.

3.1 WELL DATA

Well log data were provided in the form of LAS files, DLIS files, and scanned blue line images. Scanned images of final well reports, composite logs, and water analyses were also provided. The DLIS files were either from LIS conversions or copies of the service company DLIS files. The well data files and composite logs indicate a significant number of wells were either conventionally cored or sidewall-cored. However, the currently available regional core data include data from only three wells. The available core analysis reports included conventional porosity and permeability analysis, overburden analysis, and X-ray diffraction analysis. No reports for electrical properties or capillary pressure tests were available.

Our statistical analysis of net sand thickness, porosity, and S_w was derived from 36 regional wells with digital data including gamma ray, resistivity, bulk density, and neutron porosity measurements. We have compiled a database of the available wells to record the drill date, penetrated reservoir intervals, perforation and test intervals, and current well status. The individual well logs, referenced herein, are annotated with well test and production perforation intervals, core intervals, interpreted reservoir facies, net sand thickness, porosity, and S_w.

3.2 PRODUCTION DATA

The El Romeral License Area has three active proved developed producing wells and two shut-in wells. Gas recovery is generally via pressure depletion with limited or no aquifer support. The gas wells and their production status were summarized in Section 1.2.

3.3 SEISMIC DATA

A grid of 2-D seismic data is the primary data used to define both the contingent and prospective gas resources areas. The seismic data were processed as both normal stack and for AVO. Tarba provided the IHS Markit Kingdom software backup, which included the normal stack and AVO-processed 2-D seismic lines and culture data. The seismic data were integrated with the well data and interpreted to estimate the minimum, most likely, and maximum contingent and prospective area ranges and to identify primary depositional facies.

The seismic data are generally good for imaging reservoir presence. However, the number of prospects and definition of prospect areas are limited by the extent of the seismic data coverage. The line spacing of the 2-D seismic grid varies from approximately 0.5 to 2.0 km (0.3 to 1.2 miles) from northwest to southeast, and crossline ties of variable line length oriented from northeast to southwest are spaced 1.0 to 1.5 km (0.6 to 0.9 miles) apart (Figure 1). The northwest-to-southeast lines are approximately perpendicular to the sediment transport direction and provide good imaging of depositional geometry such as channel cut and fill deposits. The northeast-to-southwest tie lines are approximately parallel to the sediment transport direction and provide indications of connected reservoir trends between the northwest-to-southeast lines.

Seismic velocity analysis indicates that the two-way travel time (TWT) value in milliseconds is approximately equivalent to the value of the reservoir's measured depth in meters. For example, a TWT of 1,000 milliseconds occurs at a depth of approximately 1,000 m MD (3,281 ft MD).

Seismic tuning thickness was evaluated to determine the reliability of estimating prospective interval thickness from the seismic data. The ability of seismic data to define gross interval thickness is a function of seismic cycle frequency measured in hertz and the average seismic velocity measured in m or ft per second. Interval thickness below seismic tuning cannot be confidently estimated. The frequency content of the seismic data is estimated to lie between 80 and 90 hertz, limiting seismic resolution of gross interval thickness to approximately 5.6 to 6.2 m (18 to 20 ft). The thickness of many of the producing, contingent, and prospective gross reservoir intervals is greater than seismic tuning thickness, allowing gross interval thickness to be estimated directly from the seismic data. Estimated gross interval thickness above seismic tuning does not address variability in net effective reservoir thickness or porosity trends that may occur within the closure area of a field, contingent area, or prospect.

3.3.1 Seismic AVO Data

AVO seismic reprocessing was conducted on all the existing seismic data. AVO analysis is a technique used to help distinguish seismic responses due to lithology from those due to the fluid content (gas, oil, or water) in porous rocks. When properly calibrated with well log and rock property data, AVO can often be used as a direct indicator of hydrocarbon-charged reservoirs and, therefore, can significantly reduce the risk of drilling nonhydrocarbon-bearing reservoirs. As discussed herein, the AVO data are highly successful in the Guadalquivir Basin for determining gas presence and for estimating the areal extent of gas-charged porous reservoirs.

4.0 EVALUATION PROCEDURES

Volumetric estimates of OGIP and contingent and prospective gas resources were probabilistically estimated using a Monte Carlo simulation. Probability distributions were assigned to capture ranges of uncertainty in reservoir parameters. Reservoir parameters evaluated include area, gross and net thickness, net-to-gross ratio (NTG), average reservoir porosity and S_g, and B_g. Historical success of drilled gas discoveries in relation to availability of AVO-processed seismic data was assessed to estimate geologic risk factors.

Well logs were interpreted for top and base of reservoir intervals and were assigned to depositional facies categories based on attributes of fining- or coarsening-upward log character, net sand-to-shale ratio, and average porosity. Well log interpretations were integrated with the seismic data to derive four primary depositional reservoir facies. A statistical analysis of reservoir parameters was conducted by reservoir interval for each of the assigned reservoir facies to provide thickness and reservoir parameter ranges for input to the volumetric assessment of the fields, contingent areas, and prospects.

The probabilistic ranges of net thickness and area were combined in a Monte Carlo simulation, and resulting volumes were compared with P/Z analysis for the produced reservoirs. The aggregated probabilistic OGIP estimates closely match the P/Z-derived estimates, and therefore, the same methodology was applied to estimating OGIP and contingent and prospective gas resources volumes. Petrophysical cutoffs used for determination of net sand thickness were porosity greater than 15 percent and shale volume less than 45 percent. The petrophysical cutoff used for determination of net gas pay thickness was S_w less than 65 percent (35 percent S_g).

Geologic risk assessments were conducted based on the historical ratio of successful gas discoveries to the number of wells drilled relative to the availability of conventional and AVO-processed seismic data. The geologic risk assessments indicate a high probability for gas discoveries when AVO data are used for selecting drilling locations. In many instances, prospect delineation and geologic risk uncertainty will improve with acquisition of additional seismic data.

The key technical procedures used for the evaluation of in-place and contingent and prospective gas resources volumes are summarized as follows:

- Compile and inventory the well and production database.
- Interpret well log data for top and base of reservoir intervals and assign depositional facies based on well log character.
- Integrate well log analysis with the seismic data to delineate primary depositional trends and primary prospective reservoir targets.
- Conduct independent petrophysical evaluation of the following reservoir parameters: gross and net sand thickness, NTG, average interval porosity, shale volume, and S_w.
- Conduct statistical analysis to determine the probability ranges of gross and net sand thickness, NTG, porosity, and shale volume for all penetrated porous reservoir intervals and depositional

facies subunits. Conduct statistical analysis of all gas intervals to determine probability ranges of S_w for each depositional subunit.

- Evaluate seismic data to determine closure area ranges for proved and depleted reservoirs and for the contingent areas and prospects.
- Perform a probabilistic assessment of OGIP volumes of the developed reservoirs using a Monte Carlo simulation.
- Achieve an approximate probabilistic match at the mean probability of occurrence with the P/Z-based OGIP volumes.
- Apply probabilistic methods used to match the P/Z estimates of OGIP to each of the contingent and prospective reservoirs.
- Evaluate the historical ratio of gas discoveries to total number of drilled wells in relation to the availability of conventional and AVO-processed seismic data.
- Conduct a risk assessment of the probability of geologic success (P_g) for each prospect.
- Provide contingent and prospective gas resources estimates.

4.1 MONTE CARLO PROBABILISTIC ASSESSMENT

Multiple reservoir parameters described in Section 4.0 were combined to derive three Monte Carlo input variables to generate probability distributions of OGIP. The three input variables are area, average net thickness, and gas yield per acre-foot. The gas yield factor for contingent and prospective gas resources is the product of porosity, S_g, and B_g. Each input variable was assigned a probability distribution of lognormal or betaPERT, depending on the assessment of data quantity, data quality, and uncertainty related to each parameter. An output probability distribution of OGIP was calculated using the input distributions. The reservoir parameters used in the model are shown on Figure 2.

The minimum to maximum probability range of prospect area was derived from the relative uncertainty of continuous connected reservoir between available seismic lines with positive AVO. Net thickness was assigned a probability range based on the well log statistical analysis of the predominant facies interpreted from seismic data to be present over a prospective area. Seismic data indicate the predominant facies that may be present within a prospective area, but they do not provide quantitative details of NTG, porosity, S_g, or vertical and horizontal reservoir variability. Where several lines of seismic data clearly define channel scour and relatively constant channel thickness and width, the prospects were assigned to a channel cut and fill facies. Where seismic data were sparse or where no clear channel scour and fill was evident or predominant, a marginal channel facies was assigned to the contingent and prospective areas. The average reservoir porosity, S_g, and B_g were combined to calculate gas yield, and the minimum, most likely, and maximum gas yield were given a betaPERT distribution. The statistical ranges of net thickness and reservoir properties by seismic facies were input to the Monte Carlo simulation as 90 percent confidence level (P90) and 10 percent confidence level (P10) probabilities on a lognormal distribution, as shown on Figure 2.

4.2 COMPARISON OF PROBABILISTIC AND PERFORMANCE-BASED ESTIMATES OF OGIP

A comparison of statistical probability and P/Z analysis from well production records was conducted to assess the validity of the Monte Carlo probabilistic model for predicting contingent and prospective gas resources volumes. Four fields in the El Romeral License Area have sufficient production history to estimate effective reservoir volume, gas-in-place, and recovery efficiency by P/Z analysis. The P/Z analysis estimates gas reservoir volumes but does not indicate the area or internal geometry of the reservoir containing the gas volumes. Therefore, the range of producing field areas was estimated from the AVO seismic data in the same manner as contingent and prospective areas were defined.

In order to achieve a reasonable match between the P/Z and Monte Carlo volume estimates, it was necessary to apply a high degree of dependency between area and thickness range probabilities. A negative correlation coefficient was applied such that as area increases, the net thickness decreases. This inverse correlation was applied to all field, contingent area, and prospect assessments.

Our Monte Carlo mean probabilistic volumetric estimates of OGIP matched our performance-based estimates in aggregate within 15 percent for the El Romeral License Area production wells. Our P/Z analysis of OGIP for four wells in the El Romeral License Area averaged 51 MMSCM compared with the mean Monte Carlo estimate of 59 MMSCM. The P/Z-to-Monte Carlo comparison indicates that the probabilistic model is a reasonable approximation of expected ranges of OGIP estimates. The P/Z analysis is for the initial P/Z trend and does not account for any gas from low-permeability reservoir. A comparison table of the P/Z and Monte Carlo estimates for each production well and the aggregate estimated OGIP is shown on Figure 6.

4.3 HISTORICAL SUCCESS RATIO OF GAS DISCOVERIES TO DRILLED WELLS

The geologic success of a hydrocarbon gas discovery as described in this report does not imply commercial success. Small volumes of gas overlying water may be considered a geologic success in terms of a gas discovery but may not produce sufficient gas volumes to be economically viable. Additional factors such as limited or compartmentalized reservoir volumes, formation damage from drilling fluids, testing or completion practices, or mechanical failures may result in uneconomic discoveries. Historical success as discussed in this report refers to reservoir gas presence determined from well tests, gas shows while drilling, positive gas indications from well logs, or production data without regard to commerciality.

The 12 wells drilled on the El Romeral License Area consist of the following: 5 dry hole wells drilled from 1957 to 1959 (Carmona wells) without benefit of seismic data and 7 wells drilled from 1983 to 2007 based on conventional and AVO-processed 2-D seismic data, resulting in 5 commercial gas discoveries. The actual historical drilling success for the El Romeral License Area is 5 of 12 wells, or 42 percent. However, when considering only the 7 wells drilled from 1983 to 2007, the commercial discovery success rate is 5 of 7 wells, or 71 percent. Provided positive AVO data were the criteria for drilling locations, the Sevilla-2 and Sevilla-4 wells could have been drilled or sidetracked to a higher structural elevation above the interpreted GWCs, providing a 100 percent success rate for gas discoveries. It should be noted, positive AVO may represent a presence of small amounts of gas but volumes may be inadequate for commercial developments.

4.4 GEOLOGIC RISK ASSESSMENT

Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially recoverable petroleum; such risk analysis is conducted independent of estimations of petroleum volumes and without regard to the chance of development. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. A study of seismic data, well logs, well tests, and analogous fields provides additional data and supplements the risk analysis.

Prospect risks were assigned based on (1) the presence or absence and strength of positive AVO, (2) amount and quality of 2-D seismic data, (3) seismic definition of structural and stratigraphic closure, and (4) trap and seal integrity. Source rock presence is proven by existing production and is not considered a risk. By carefully examining the subcategories under each of these components and assigning them a confidence ranking, a numerical risk value can be calculated. The product of these four risk factors yields the relative P_g. Otis and Schneidermann (1997) define a P_g greater than 0.50 as very low risk, a P_g between 0.50 and 0.25 as low risk, a P_g between 0.25 and 0.125 as moderate risk, a P_g between 0.125 and 0.0625 as high risk, and a P_g below 0.0625 as very high risk. As an example, a P_g of 0.10 suggests that a prospect has a 1-in-10 chance of discovering hydrocarbons, without regard to their commerciality. For most of the higher risked prospects, the risk estimate assigned can be improved with the acquisition of additional seismic data. This approach to prospect risking is an industry-standard technique that provides an effective and consistent method to quantitatively evaluate and rank prospects across an entire exploration portfolio. Prospects with dual drilling objectives are risked independently for the vertically separated reservoirs. There are two dual-objective prospects on the El Romeral License Area.

The El Romeral License Area prospects have variable DHI support and are considered low-risk opportunities for gas discoveries. It should be noted that the AVO-processed seismic data do not entirely remove prospect risk, as indicated by the subcommercial wells near the GWC, or in the case of marginal-quality or high-S_w reservoirs. The AVO-processed and conventional seismic data do not resolve net effective reservoir thickness, effective porosity, or total gas content. Small volumes of gas overlying water or gas trapped within a water column can provide a positive AVO effect as can lithological variations. There are other criteria, such as trap definition and reservoir quality and continuity, necessary for defining the risks associated with each of the prospects evaluated. The acquisition of additional seismic data could improve the definition of prospect area and thickness and could assist in locating wells in optimal positions for improved gas recovery. A 3-D seismic survey calibrated with well data may provide data that, through seismic inversion processes, may be predictive of porosity, NTG, or S_g. Seismic inversion technology is being used successfully in many basins of the world with lower frequency content than has been acquired in the Guadalquivir Basin.

5.0 CONTINGENT GAS RESOURCES

There are two wells in the El Romeral License Area that penetrate positive AVO signatures with well tests and/or well log data, confirming gas-bearing reservoir intervals that were not completed as producing wells. These wells penetrate GWCs where seismic data indicate continuous reservoir likely extends updip of the GWC. Data obtained from these wells are summarized as follows:

- Sevilla-2, located on the El Romeral-1 License Block, is directly on the edge of positive AVO signature and encountered minor gas shows while drilling from 590 to 601 m MD (1,936 to 1,972 ft MD). Well tests recovered trace gas and formation water. Log analysis indicates this well penetrated 1.8 m of net sandstone with 50 percent S_g overlying 7.2 m of net water sand. The well penetrated the top of the reservoir interval near the GWC interpreted at 594 m MD (1,948 ft MD), as shown on the well log on Figure 7.

  The area updip of the GWC is subdivided into a contingent resources area and a prospective resources area. The interpreted connected reservoir to the Sevilla-2 well has seismically defined minimum and most likely areas of 0.9 and 2.0 km^2 (222 and 493 acres), respectively. A 1996-vintage seismic line with no AVO response separates the contingent area from the prospective resources area. The contingent resources area is designated as the Tarazona Contingent Area.

- Sevilla-4, located on the El Romeral-1 License Block, penetrated 1.8 m of net gas reservoir overlying a 24.3-m net water interval. A GWC is interpreted at 721 m MD (2,366 ft MD) (Figure 8). The gas reservoir was tested at a relatively low daily rate of 7.2 MSCM (253 thousand cubic feet). The channel cut and fill facies observed in this well are interpreted from multiple seismic dip lines to potentially extend northeast and updip of the GWC for a distance of approximately 17 km (10.6 miles) to the northeast and to cover a maximum area of 9.14 km^2 (2,259 acres).

  The area updip of the GWC is subdivided into a contingent resources area and a prospective resources area. The most likely contingent resources area is 1.7 km^2 (420 acres), corresponding to the average estimated drainage area of the four producing and depleted wells in the El Romeral License Area. The maximum contingent area is 4.0 km^2 (994 acres) and is designated as the Romeral-4 Sur Contingent Area (Figure 1). The updip prospective resources area is designated as the Romeral-1 Prospect. This channel complex extends southwest to northeast along and across the southern license boundary and possibly has a tortuous reservoir connection to the Romeral-4 Sur Contingent Area.

We estimate the discovered OGIP and unrisked gross (100 percent) contingent gas resources for the Romeral-4 Sur and Tarazona Contingent Area, as of June 30, 2019, to be:

	Discovered OGIP (MMSCM)			Unrisked Gross (100%) Contingent Gas Resources (MMSCM)		
Contingent Area	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Romeral-4 Sur	72.6	111.5	157.8	57.7	93.1	138.8
Tarazona	38.9	59.8	85.9	30.0	48.9	74.5
Total[(1)]	111.5	171.3	243.7	87.7	142.0	213.3

(1) Totals are the arithmetic sum of multiple probability distributions.

A representative seismic line for each contingent area is shown on Figures 9 and 10, and a summary of key details pertaining to each seismic line is provided in the following table:

Contingent Area	Seismic Figure	Notes
Romeral-4 Sur	Figure 9	Updip of GWC (721 m MD [2,366 ft MD]) penetrated by Sevilla-4 well; 1.8 m net gas; gross channel sand 31 m; porosity of 22 percent; shale volume of 34 percent.
Tarazona	Figure 10	Updip of GWC (594 m MD [1,948 ft MD]) penetrated by Sevilla-2 well; 1.8 m net gas; gross channel sand 18 m; AVO improvement over the Sevilla-2; porosity of 26 percent; shale volume of 36 percent.

6.0 PROSPECTIVE GAS RESOURCES

Our probabilistic resources assessment input parameters of area, net thickness, and gas yield for each prospect are summarized on Figure 2. The map on Figure 1 includes location and coverage of seismic data, wells drilled, and maximum prospect polygons.

We estimate the undiscovered OGIP, unrisked and risked gross (100 percent) prospective gas resources, and P_g for these prospects, as of June 30, 2019, to be:

	Undiscovered OGIP (MMSCM)			Gross (100%) Prospective Gas Resources (MMSCM) Unrisked			Gross (100%) Prospective Gas Resources (MMSCM) Risked			
Prospect	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	Low Estimate (1U)	Best Estimate (2U)	High Estimate (3U)	P_g
Aventurado Norte	519.1	842.5	1,256.7	415.2	707.2	1,109.5	311.4	530.4	832.1	0.75
Aventurado Sur	447.6	717.5	1,060.1	341.4	580.9	913.0	256.0	435.7	684.7	0.75
Cervatillo	42.2	64.4	92.1	31.1	50.8	77.8	25.2	41.1	63.0	0.81
Gamo	62.7	100.4	147.6	46.3	79.3	125.0	39.4	67.4	106.3	0.85
Rio Corbones Oeste (Uceda)	58.7	115.2	199.4	39.9	85.6	162.1	33.9	72.7	137.8	0.85
Romeral-1 Sand 1	147.9	315.1	594.3	117.5	263.1	522.7	105.7	236.8	470.4	0.90
Romeral-1 Sand 2	21.4	84.5	246.3	17.0	70.5	216.6	8.5	35.3	108.3	0.50
Romeral-2 Sur Sand	170.5	320.1	531.0	128.8	257.3	455.1	104.4	208.4	368.6	0.81
Romeral-2 Upper Sand	24.8	50.2	93.2	18.7	40.4	79.9	13.1	28.2	55.9	0.70
Romeral-3	63.6	114.2	185.4	43.3	85.0	150.9	35.1	68.8	122.2	0.81
Saltillo	109.5	216.8	374.0	86.6	180.4	328.2	70.2	146.2	265.9	0.81
San Pablo	30.2	46.0	65.2	23.9	38.4	57.4	18.0	28.8	43.0	0.75
Santiche	74.2	122.1	181.9	59.4	102.5	160.6	41.6	71.8	112.4	0.70
Total[1]	1,772.5	3,109.0	5,027.1	1,369.2	2,541.3	4,358.8	1,062.4	1,971.5	3,370.8	

[1] Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

A representative seismic line for each prospect is shown on Figures 11 through 22, and a summary of key details pertaining to each seismic line is provided in the following table:

Prospect	Seismic Figure	Notes
Aventurado Norte	Figure 11	Multiple dip lines and one strike line; estimated maximum thickness of 20 m indicates channel-fill trend; moderate to good AVO.
Aventurado Sur	Figure 12	Multiple dip lines and one strike line; mostly parallel reflectors; possible marginal channel and overbank deposits.
Cervatillo	Figure 13	Four dip lines and one strike line; moderate AVO; similar to El Ciervo-1 Field marginal channel facies (3.4 m net gas) (best producer at El Romeral).
Gamo	Figure 14	Nine dip lines; adjacent to or structurally lower than El Ciervo-1 Field; moderate AVO; erosional top from overlapping El Ciervo-1 Field.
Rio Corbones Oeste (Uceda)	Figure 15	Added polygon as downdip disconnected channel extension to Rio Corbones-1 well (drilled in 2007); early water breakthrough.
Romeral-1	Figure 16	Multiple dip lines along and across southern border of license boundary; updip of Sevilla-4 well with improved AVO strength.
Romeral-2	Figures 17 & 18	Dual objective across and along the license; channel lobe with faint to moderate AVO.
Romeral-3	Figure 19	Structurally above Aventurado Sur Prospect; multiple dip lines; moderate to poor AVO; channel to marginal channel facies.
Saltillo	Figure 20	Six dip lines with two target intervals possible; four good lines with indicated channel lithofacies and AVO; estimated gross thickness of 20 m.
San Pablo	Figure 21	Two dip lines and one strike line; downdip of and on trend with Sevilla-2; moderate to weak AVO.
Santiche	Figure 22	Flanking marginal channel facies at Sevilla-1 well; 3.4 m net sand; porosity of 27 percent; S_w of 58 percent.

7.0 CONCLUSIONS

The fields, contingent areas, and prospects represent a statistical play such that area, reservoir thickness, discovery success, gas in-place, and recovery efficiency are variable within predictive ranges. The potential range of contingent and prospect areas and net reservoir thickness relies on integration of interpreted well log data, the 2-D seismic data grid, and historical production data. The interpreted well log data provide a statistical range of gross and net rock interval thickness, porosity, shale volume, and S_g in relation to depositional facies. The interpreted grid of 2-D seismic data provides estimated ranges of closure area. Performance analysis of producing or depleted reservoirs provides direct analogs of net effective reservoir volume and in-place gas volume for validating the net rock volume and OGIP estimated by Monte Carlo methods. Historical drilling success and the amount and quality of seismic data provide an indication of associated risk of gas discoveries. A 75 to 80 percent success ratio of gas discoveries to drilled wells is considered a reasonable assessment of risk with the current seismic data. This success ratio would be expected to improve with additional 2-D seismic data or, ideally, with acquisition of 3-D seismic data.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2018 Petroleum Resources Management System definitions and guidelines. The contingent and prospective resources shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Tarba, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists.

FIGURES

NETHERLAND, SEWELL
& ASSOCIATES, INC.

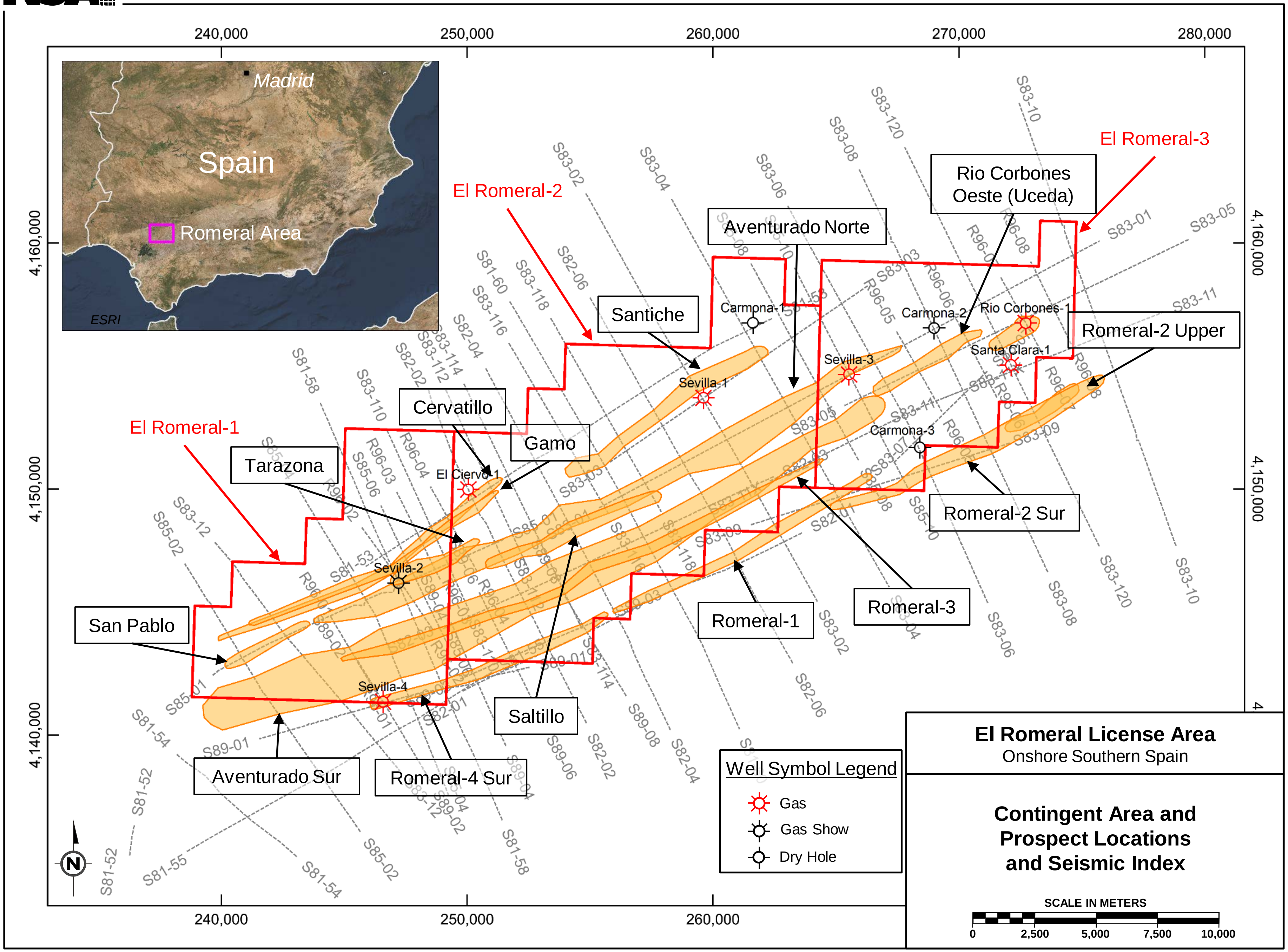


Figure 1

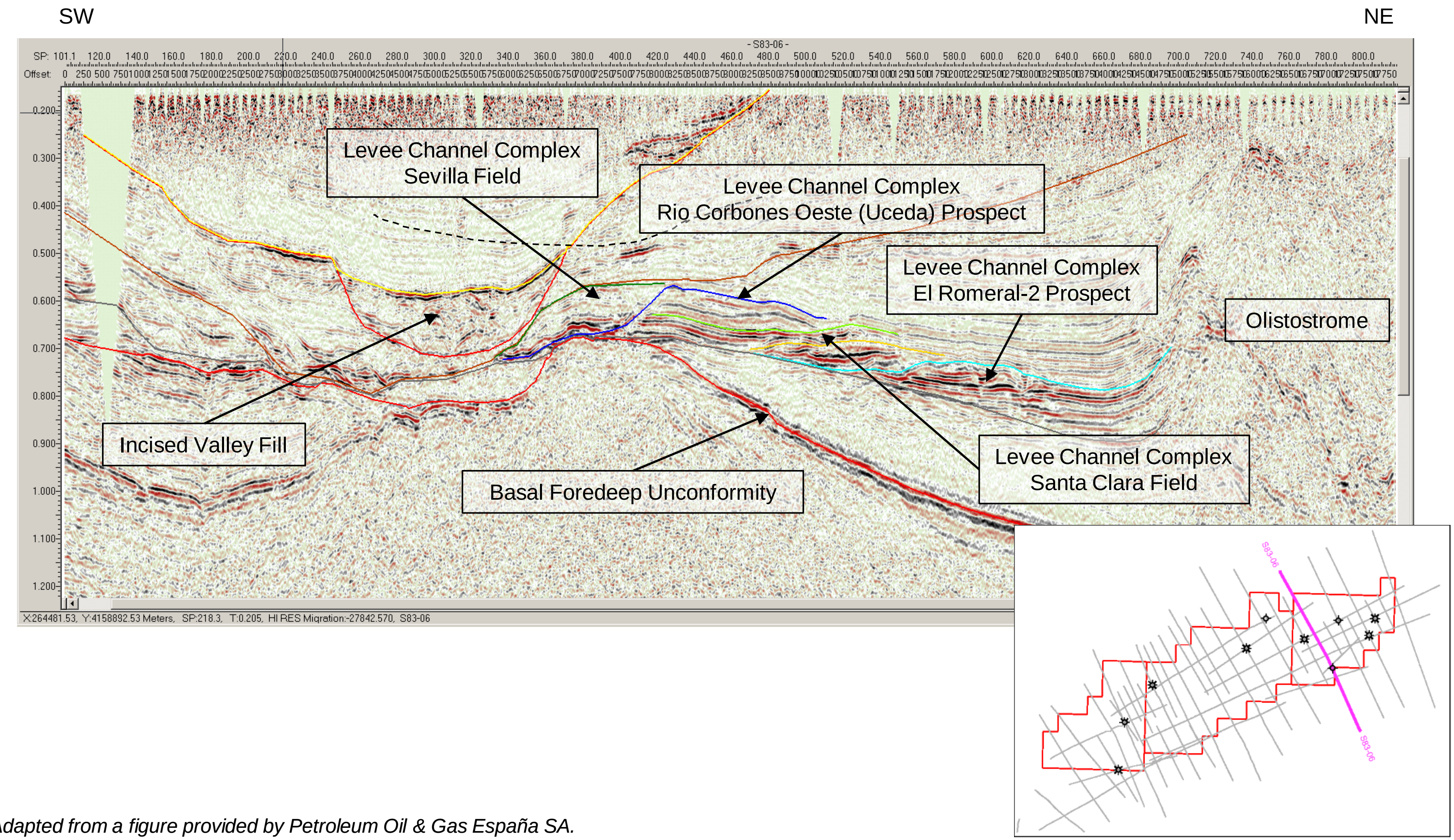
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

VOLUMETRIC INPUT PARAMETERS
EL ROMERAL LICENSE AREA, ONSHORE SOUTHERN SPAIN
AS OF JUNE 30, 2019

Contingent Area or Prospect/Sand	Area (acres)			Net Thickness (ft)		Porosity (decimal)			S_g (decimal)			Gas Yield (MCF/ac-ft)		
	P95	P50	P5	P90	P10	Min	ML	Max	Min	ML	Max	Min	ML	Max
Contingent Area														
Romeral-4 Sur	175	420	994	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	199	407	791
Tarazona	222	493	756	7.6	35.2	0.16	0.24	0.32	0.36	0.49	0.69	150	305	573
Prospect														
Aventurado Norte	1,658	2,985	5,618	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	204	418	811
Aventurado Sur	845	3,005	11,788	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	174	357	693
Cervatillo	275	549	1,155	7.6	35.2	0.16	0.24	0.32	0.36	0.49	0.69	130	265	498
Gamo	243	457	900	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	159	326	632
Rio Corbones Oeste (Uceda)	479	614	778	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	131	269	522
Romeral-1 Sand 1	989	1,117	1,264	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	199	407	791
Romeral-1 Sand 2	36	500	6,700	7.6	35.2	0.17	0.26	0.36	0.41	0.55	0.77	199	407	791
Romeral-2 Sur Sand	947	1,335	1,923	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	169	347	674
Romeral-2 Upper Sand	341	392	450	7.6	35.2	0.16	0.24	0.32	0.36	0.49	0.69	140	286	536
Romeral-3	796	1,145	1,640	7.6	35.2	0.16	0.24	0.32	0.36	0.49	0.69	109	222	417
Saltillo	594	773	1,024	11.4	57.6	0.17	0.26	0.36	0.41	0.55	0.77	196	401	779
San Pablo	143	370	568	7.6	35.2	0.16	0.24	0.32	0.36	0.49	0.69	164	335	629
Santiche	465	793	1,408	7.6	35.2	0.16	0.24	0.32	0.36	0.49	0.69	168	344	645

Figure 2

2-D Seismic Strike Line S83-06
El Romeral License Area, Onshore Southern Spain

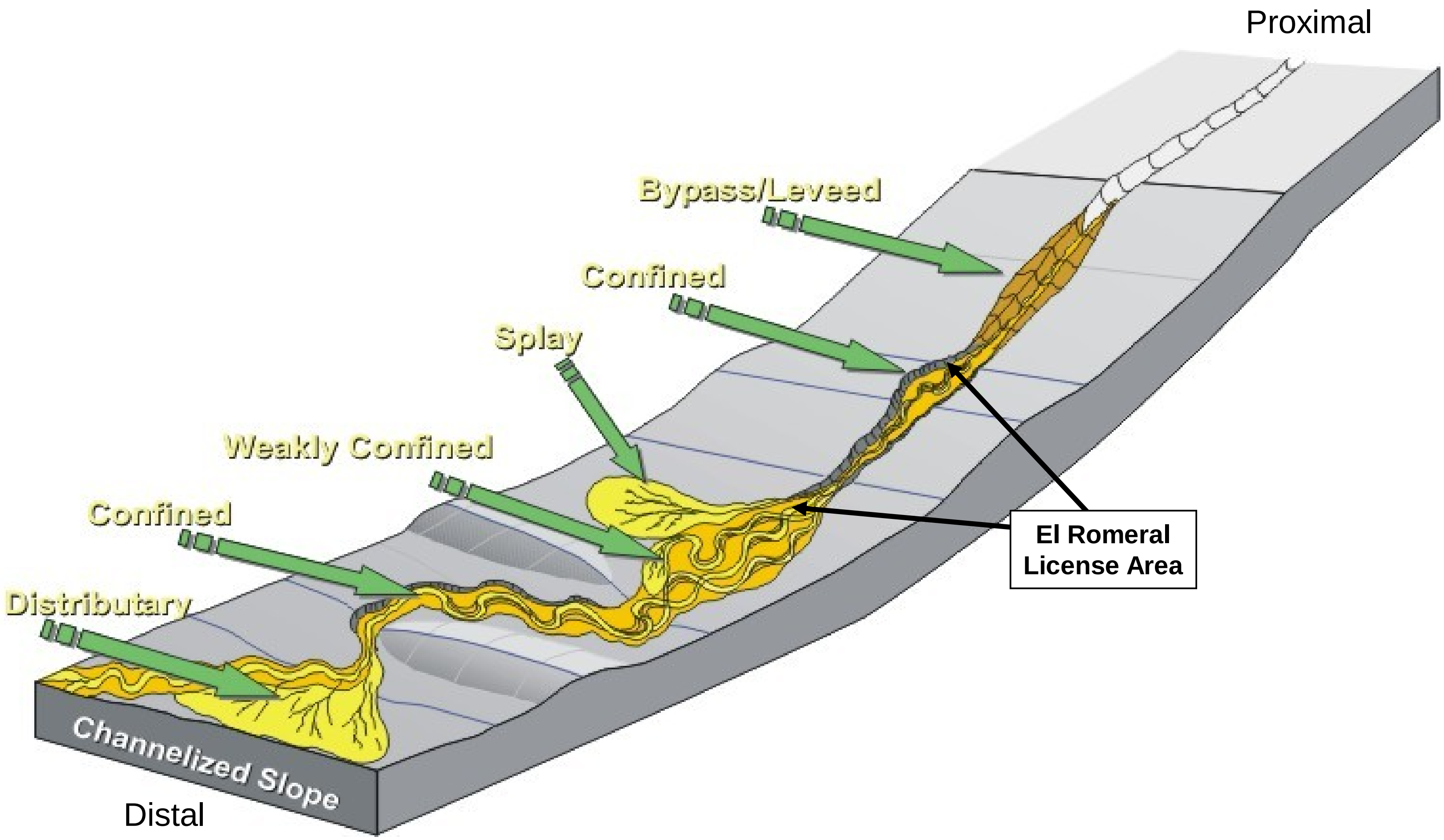


Adapted from a figure provided by Petroleum Oil & Gas España SA.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3

Turbidite Depositional System



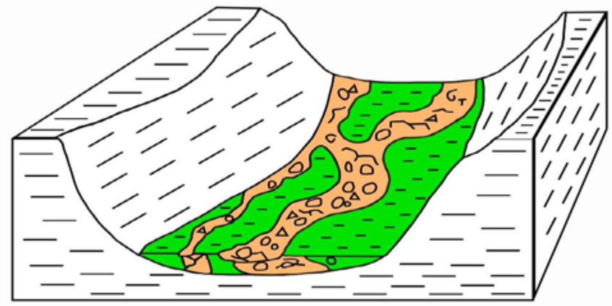
Adapted from Sprague et al., 2003.

Figure 4

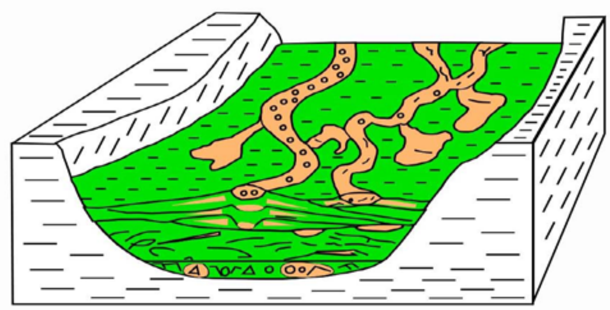
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Succession of Valley Cut and Fill and Subsequent Erosion

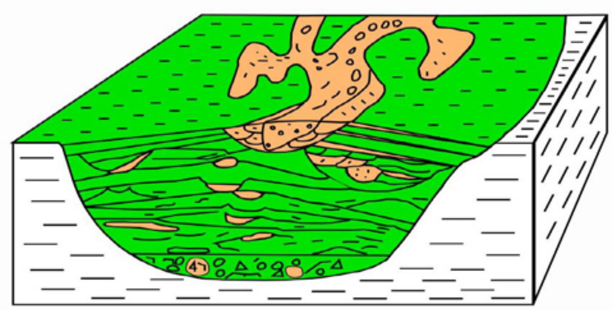
1. Valley Incision of Marine Substrate
   a. Slumps
   b. Debris flows
   c. Channel wall caving
   d. Poorly sorted, mixed coarse-grained and fine-grained deposits



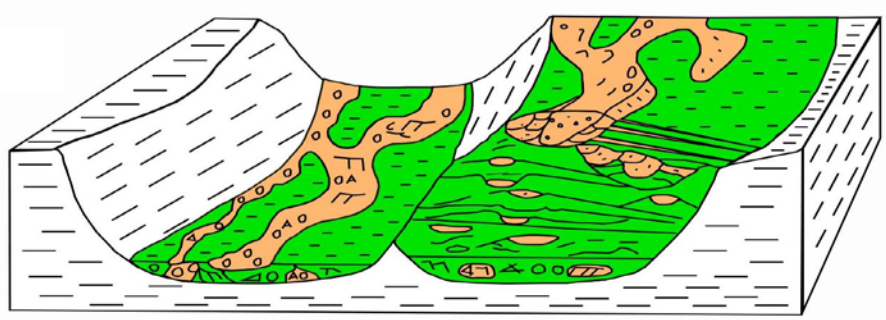
2. Early to Middle Valley Infill
   a. Confined sinuous channels and channel overbank
   b. Complex of amalgamated intersecting channels
   c. Partial preservation of channel and channel overbank facies due to reincision
   d. Slumps and debris flows common at channel bases
   e. Fining-upward grain size
   f. Laminated overbank deposits



3. Middle to Late Valley Infill
   a. Stacked amalgamated channel and channel overbank facies
   b. Erosion and reincision of previous channels
   c. Last channel cut in sequence preserved
   d. Channel abandonment



4. Successive Valley Scour
   a. Channel abandonment accompanied by successive valley incision to the north of the initial valley scour
   b. Possibly related to basin tilting
   c. Fill process repeated



COMPARISON OF P/Z AND MONTE CARLO MEAN ESTIMATES OF OGIP
EL ROMERAL LICENSE AREA, ONSHORE SOUTHERN SPAIN
AS OF JUNE 30, 2019

	OGIP (MMSCM)		Δ P/Z to Monte Carlo Mean
Well	Monte Carlo Mean Estimate	P/Z Estimate	(Percent)
El Ciervo-1	116	105	91
Santa Clara-1	45	32	71
Sevilla-1	18	16	89
Sevilla-3	57	51	89
Total	236	204	86
Average	59	51	86

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Well Log – Sevilla-2
El Romeral License Area, Onshore Southern Spain

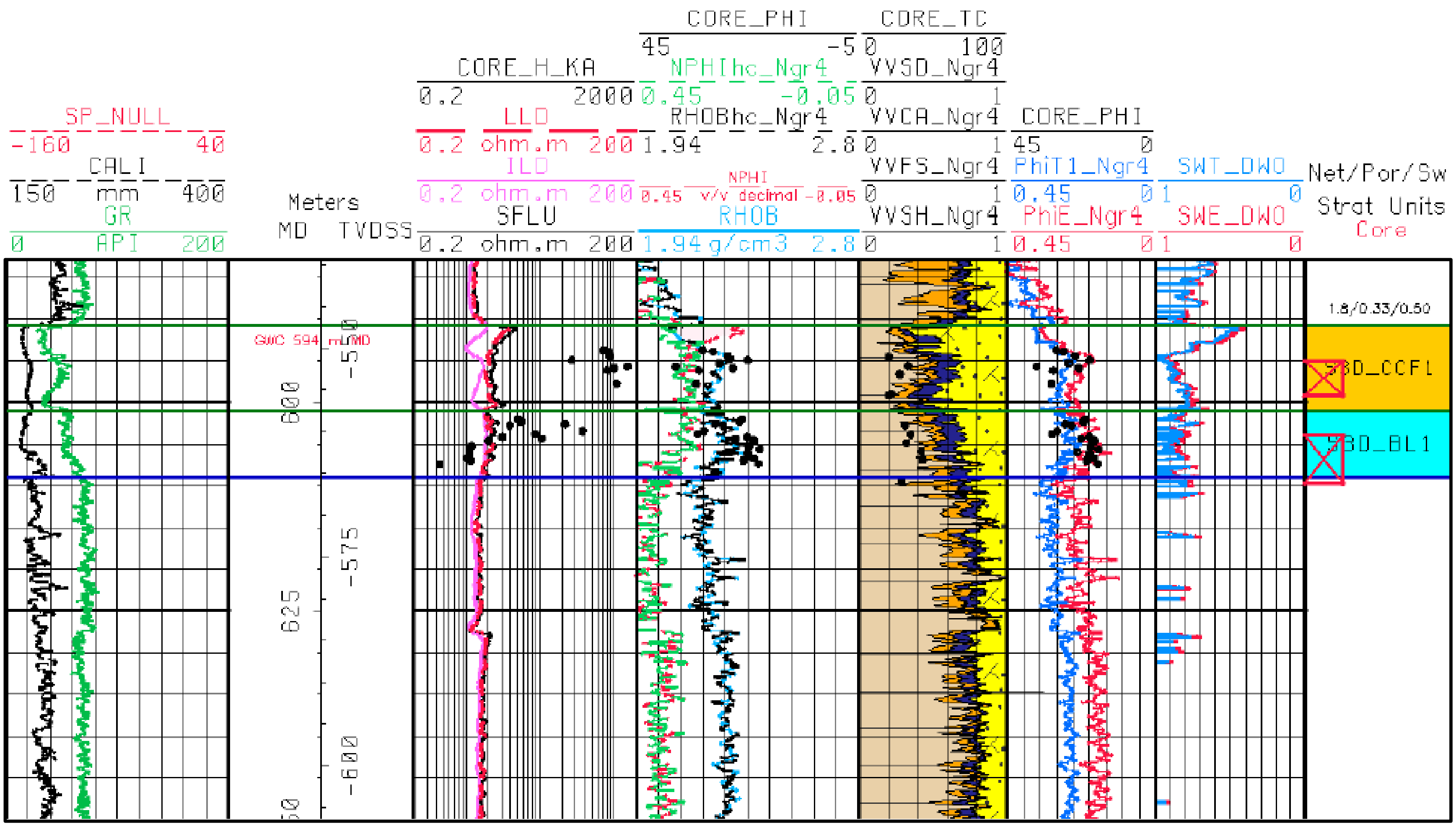


Figure 7

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Well Log – Sevilla-4
El Romeral License Area, Onshore Southern Spain

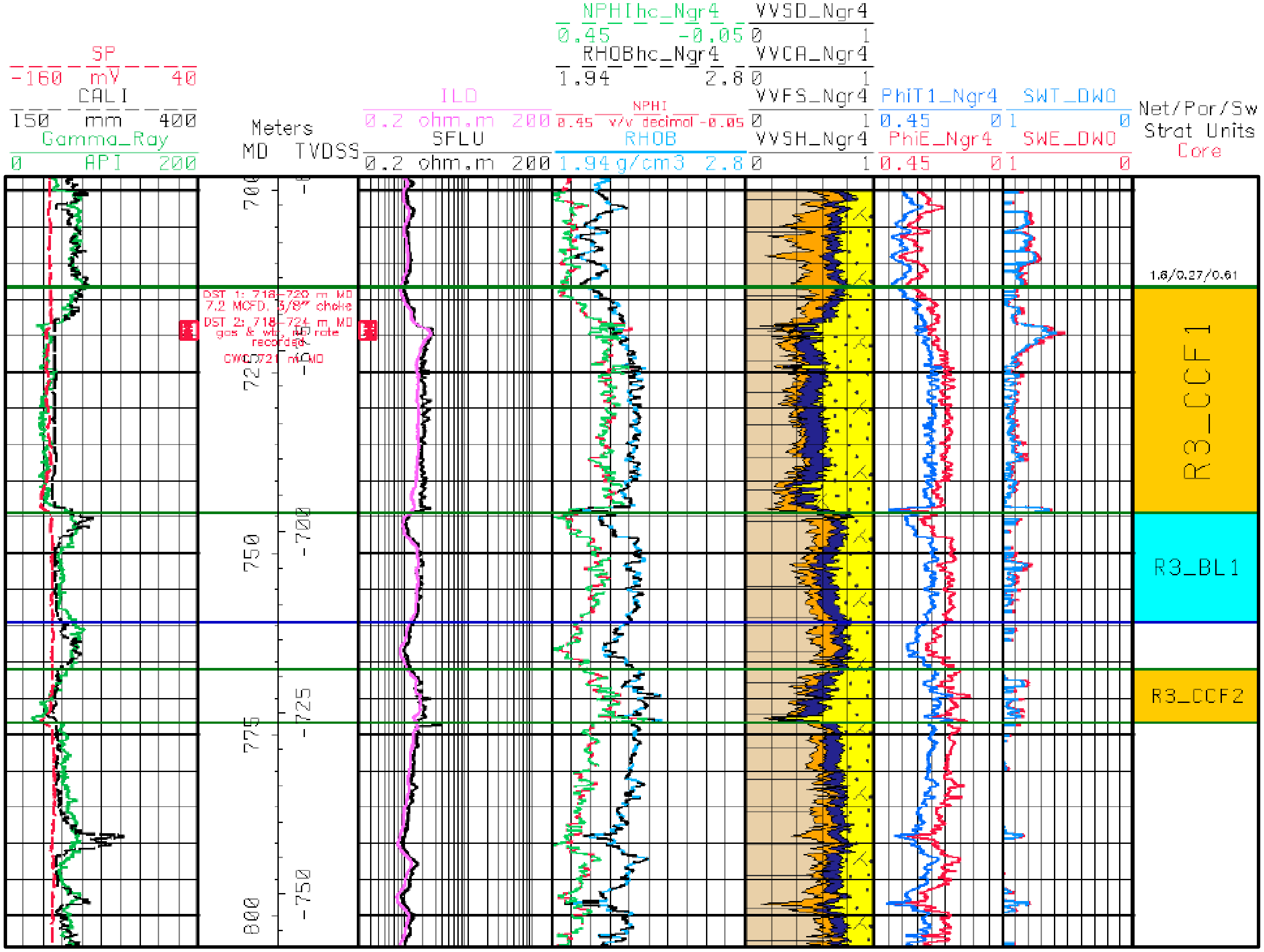


Figure 8

2-D Seismic Strike Line S89-01
Romeral-4 Sur Contingent Area
El Romeral License Area, Onshore Southern Spain

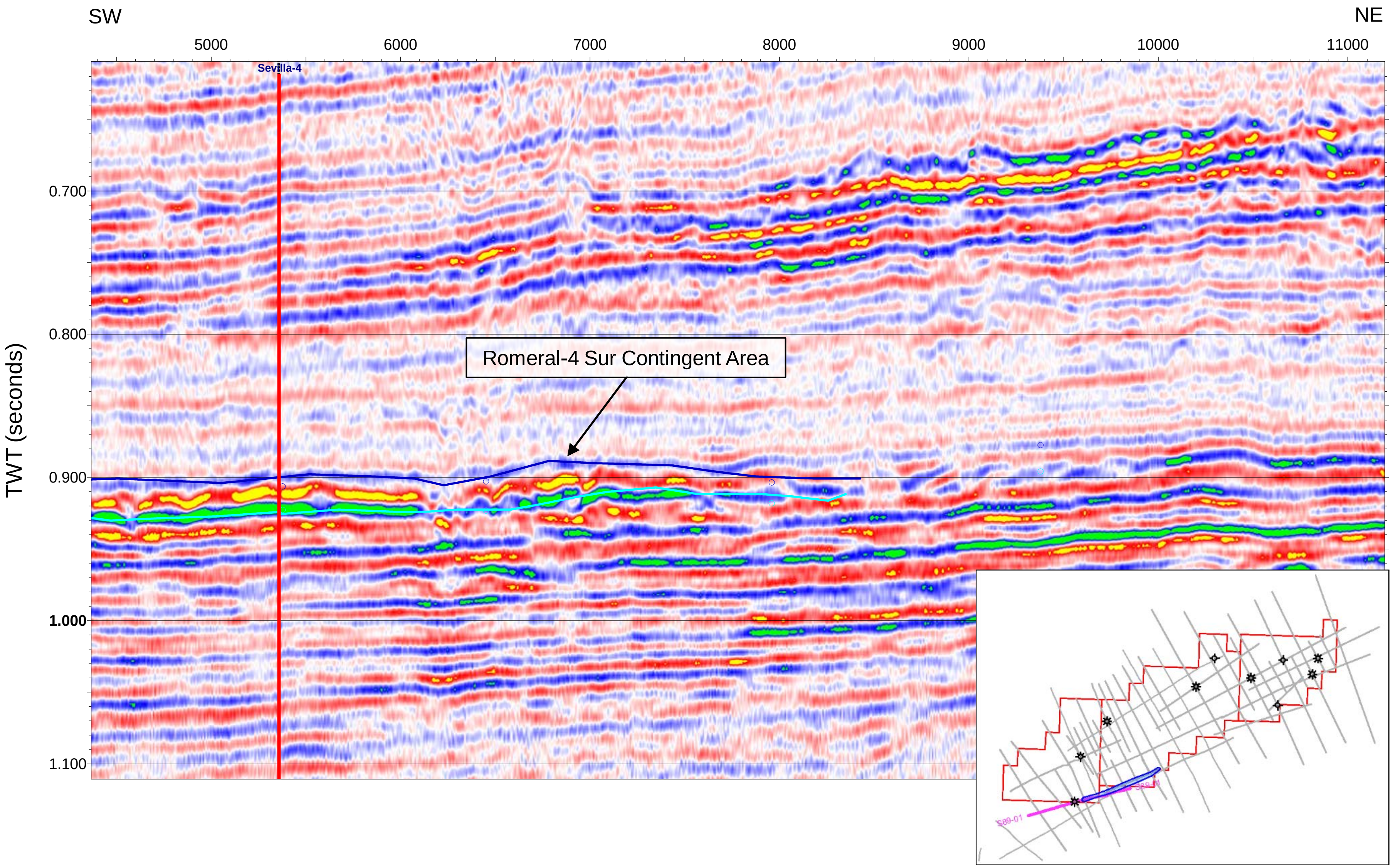


Figure 9

2-D Seismic Strike Line S85-01
Tarazona Contingent Area
El Romeral License Area, Onshore Southern Spain

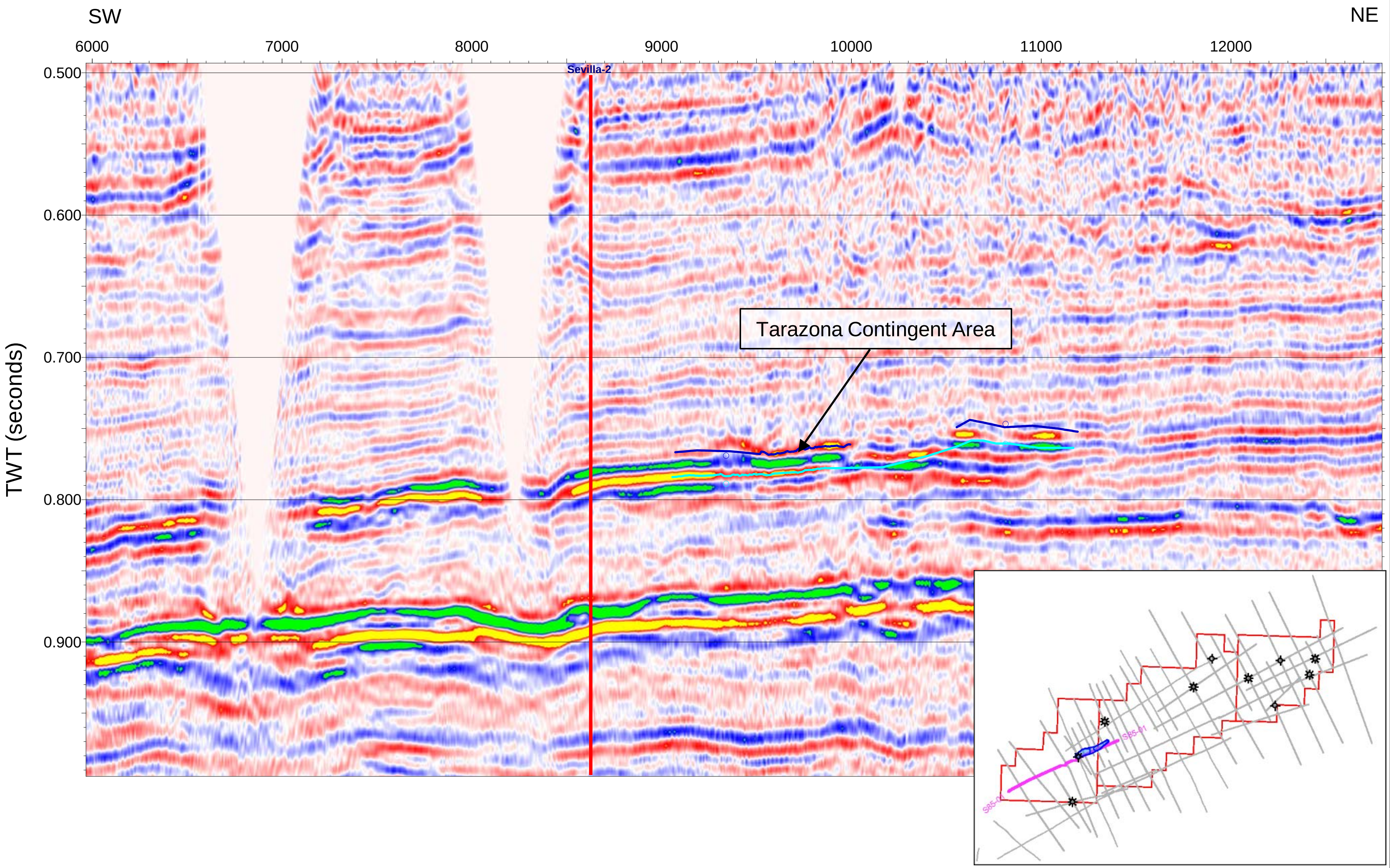


Figure 10

2-D Seismic Strike Line S83-01
Aventurado Norte Prospect
El Romeral License Area, Onshore Southern Spain

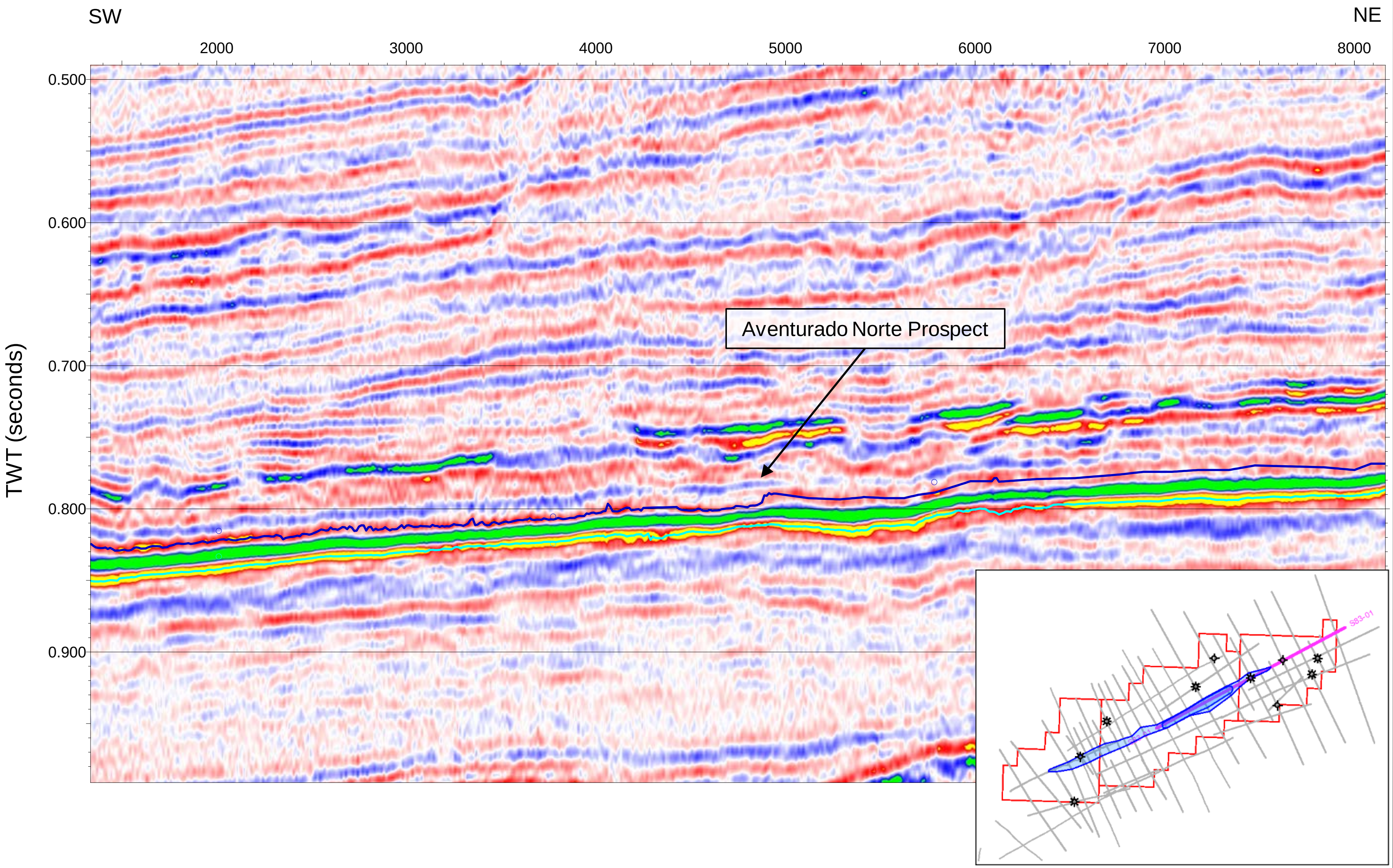


Figure 11

2-D Seismic Dip Line S85-08
Aventurado Sur Prospect
El Romeral License Area, Onshore Southern Spain

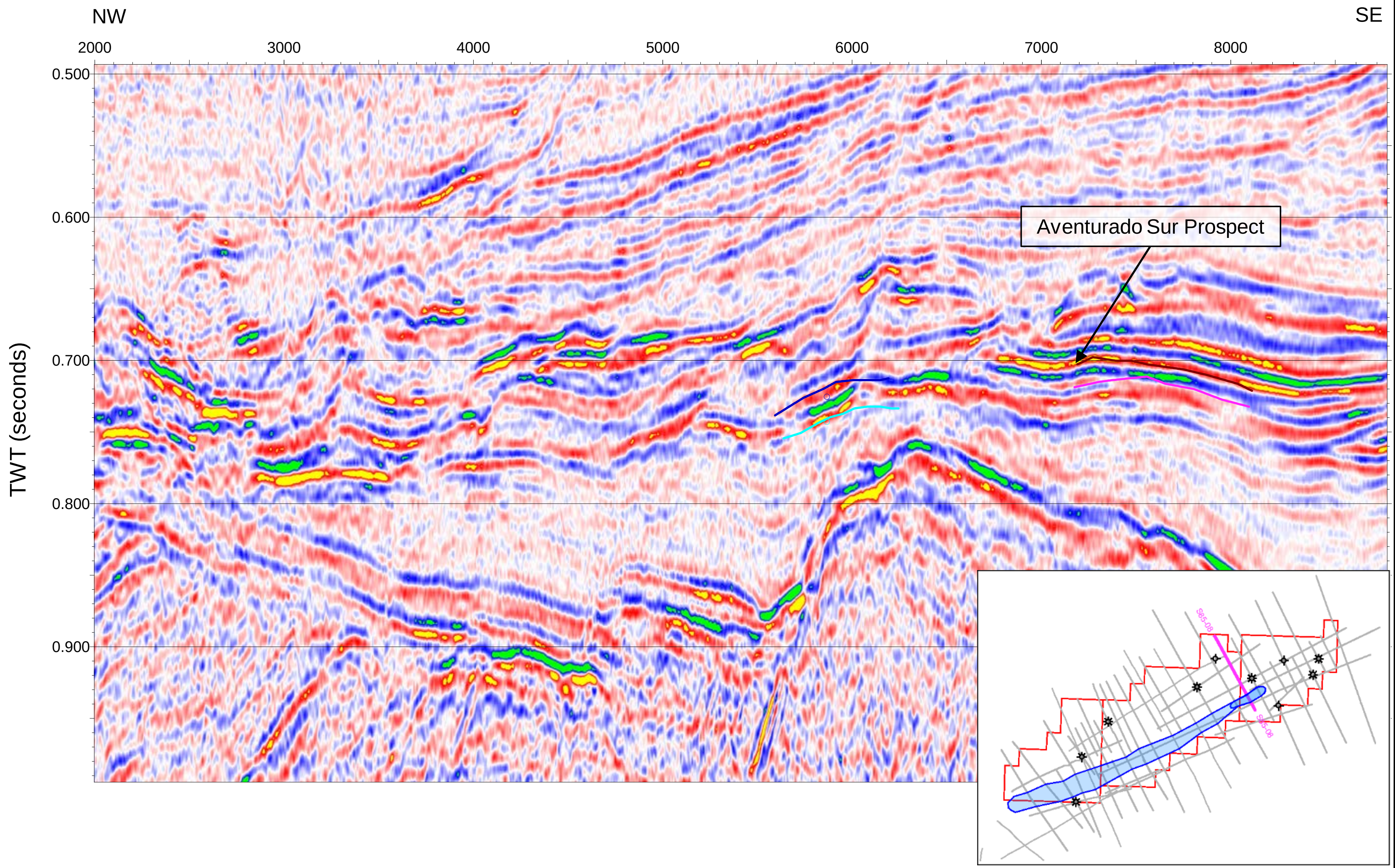


Figure 12

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2-D Seismic Strike Line S81-53
Cervatillo Prospect
El Romeral License Area, Onshore Southern Spain

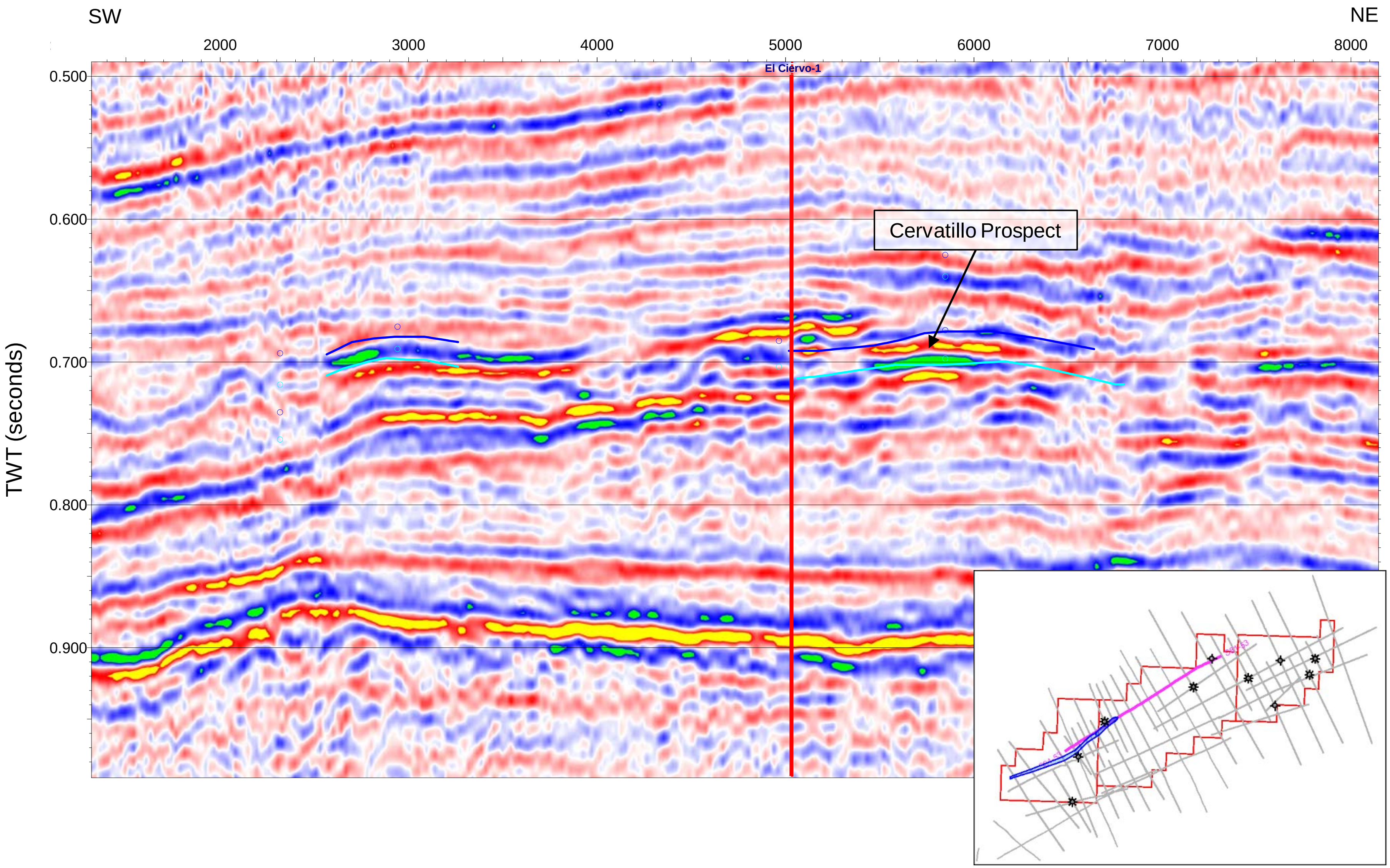


Figure 13

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

2-D Seismic Dip Line S82-02
Gamo Prospect
El Romeral License Area, Onshore Southern Spain

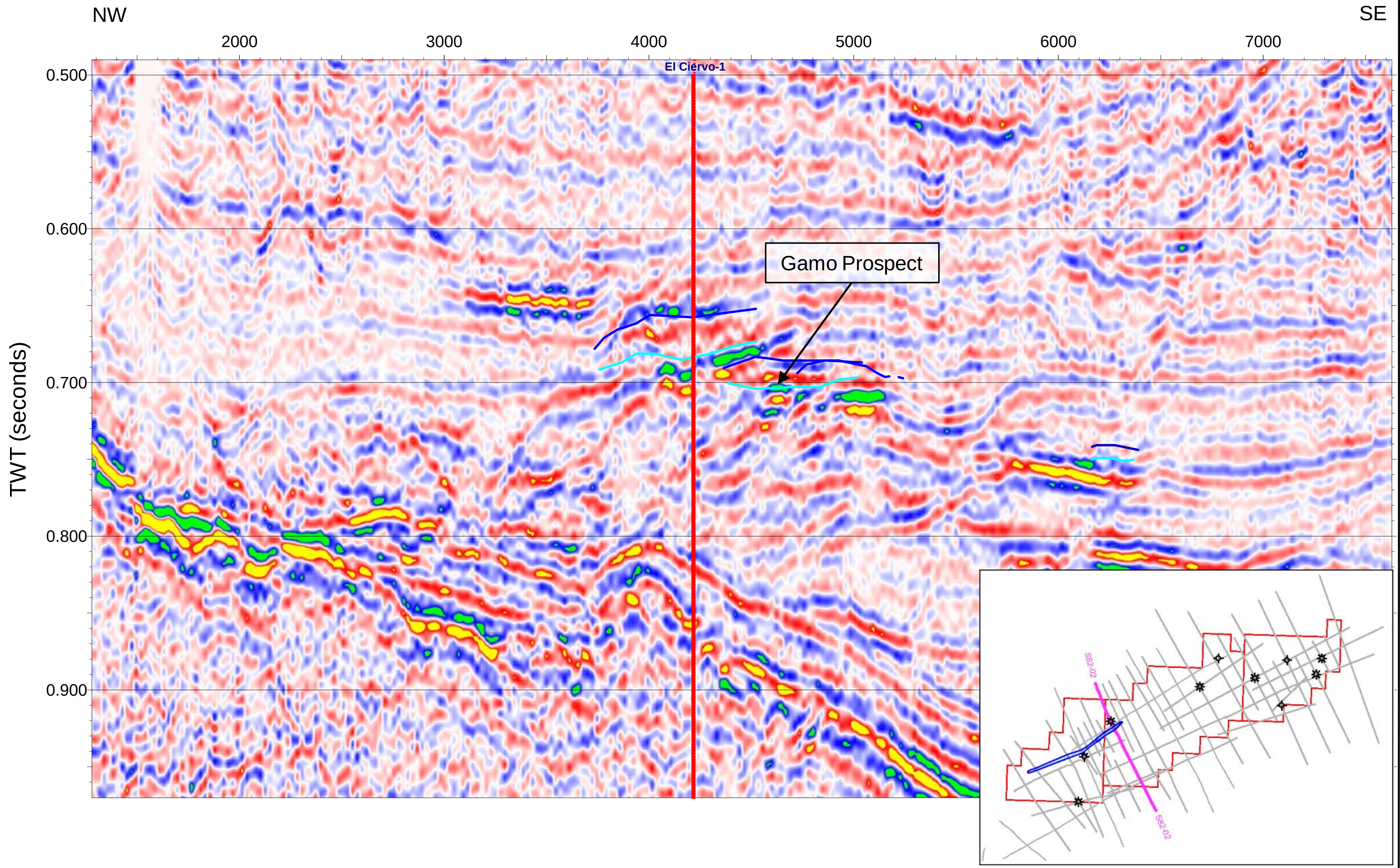


Figure 14

2-D Seismic Strike Line S83-05
Rio Corbones Oeste (Uceda) Prospect
El Romeral License Area, Onshore Southern Spain

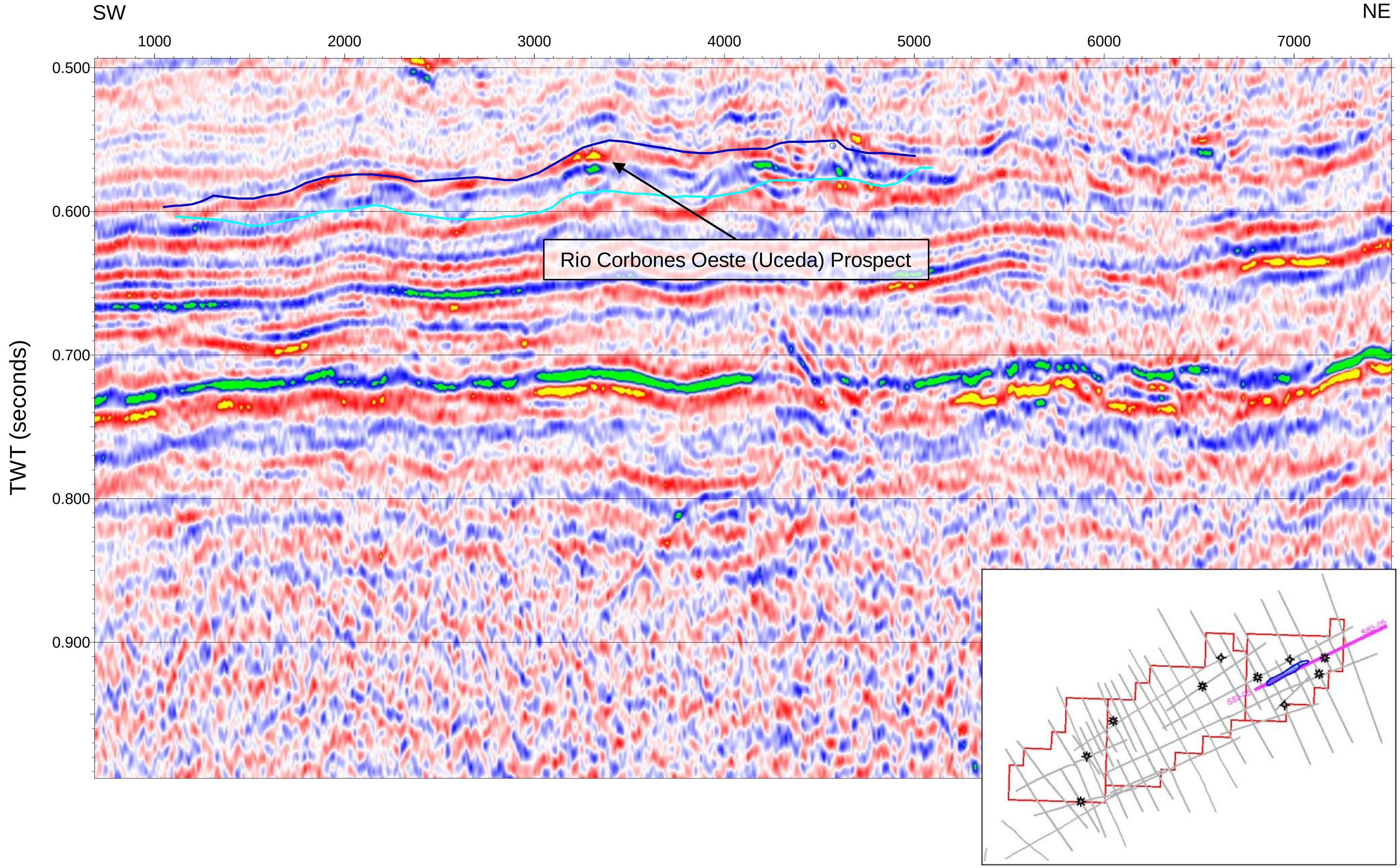
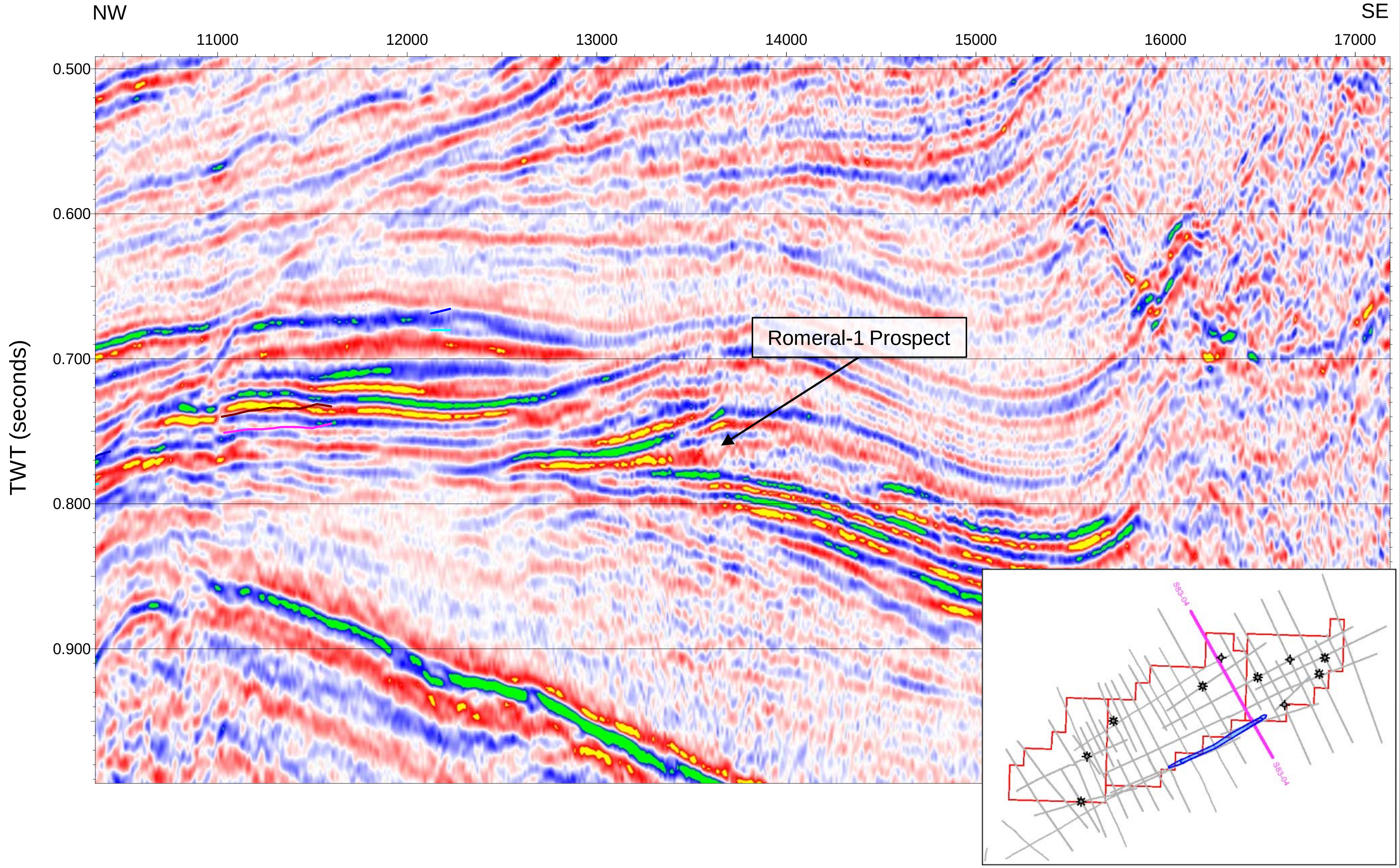


Figure 15

2-D Seismic Dip Line S83-04
Romeral-1 Prospect
El Romeral License Area, Onshore Southern Spain



All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

2-D Seismic Dip Line S83-08
Romeral-2 Sur Sand Prospect
El Romeral License Area, Onshore Southern Spain

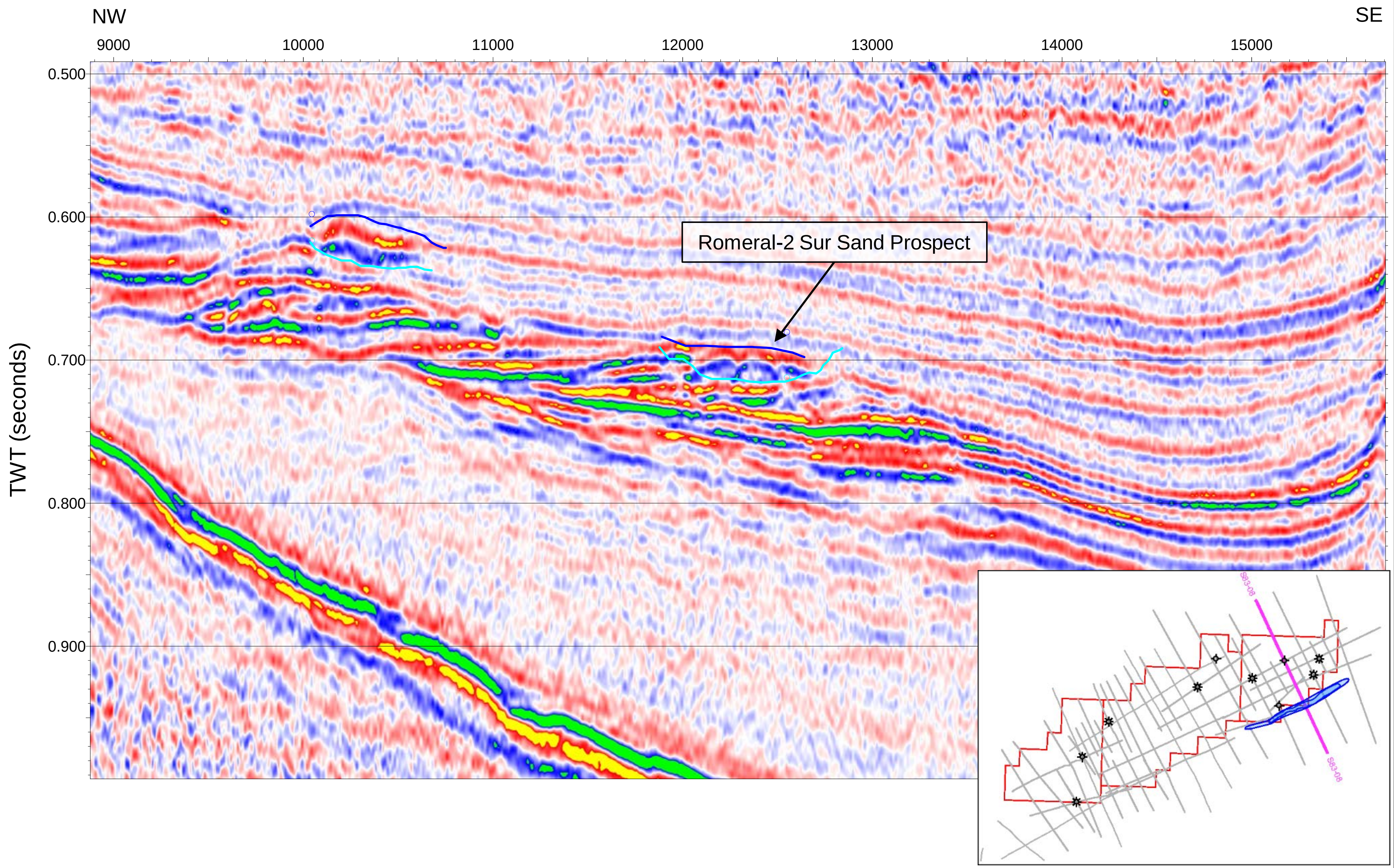


Figure 17

2-D Seismic Dip Line S83-120
Romeral-2 Upper Sand Prospect
El Romeral License Area, Onshore Southern Spain

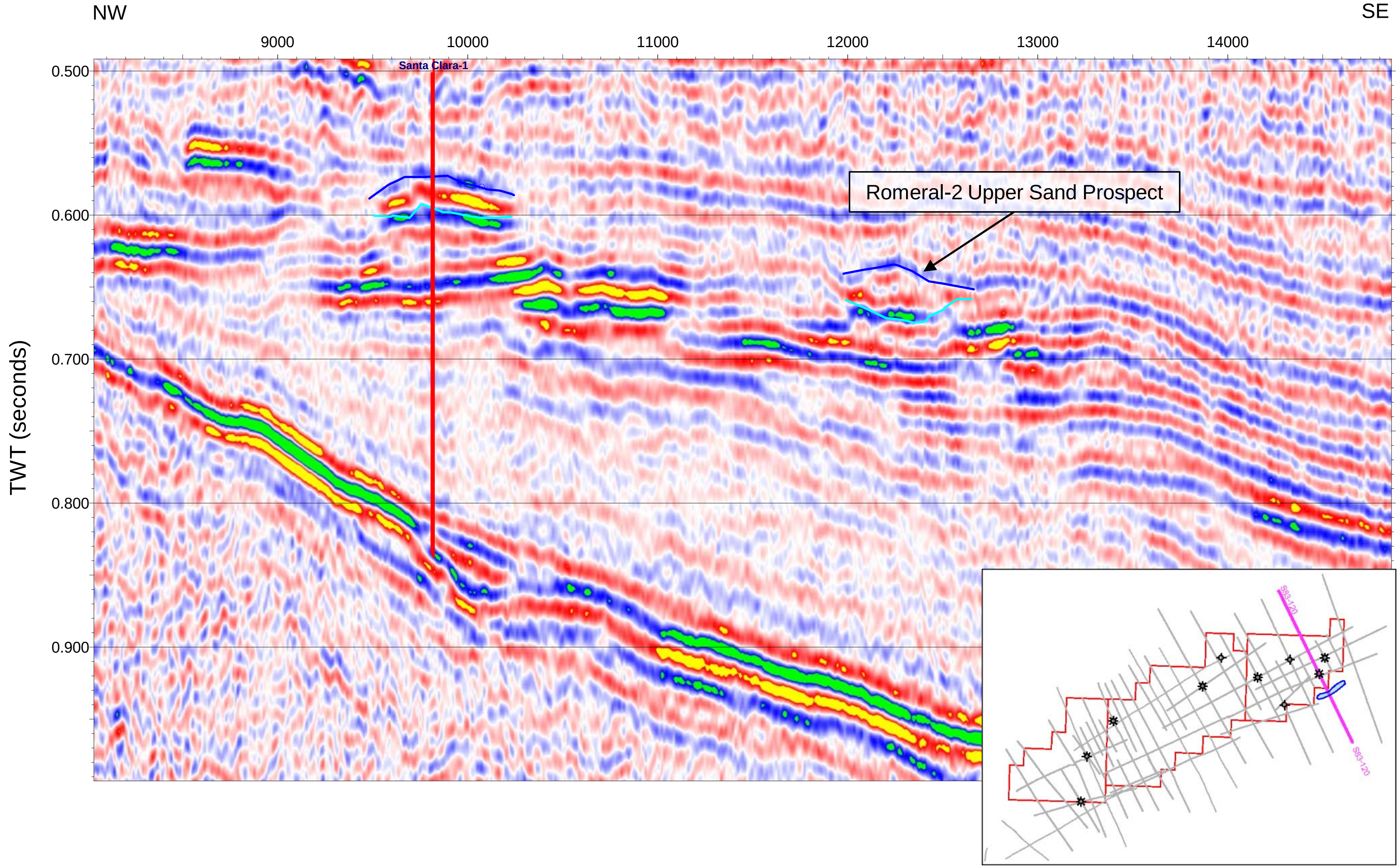


Figure 18

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

2-D Seismic Dip Line S82-04
Romeral-3 Prospect
El Romeral License Area, Onshore Southern Spain

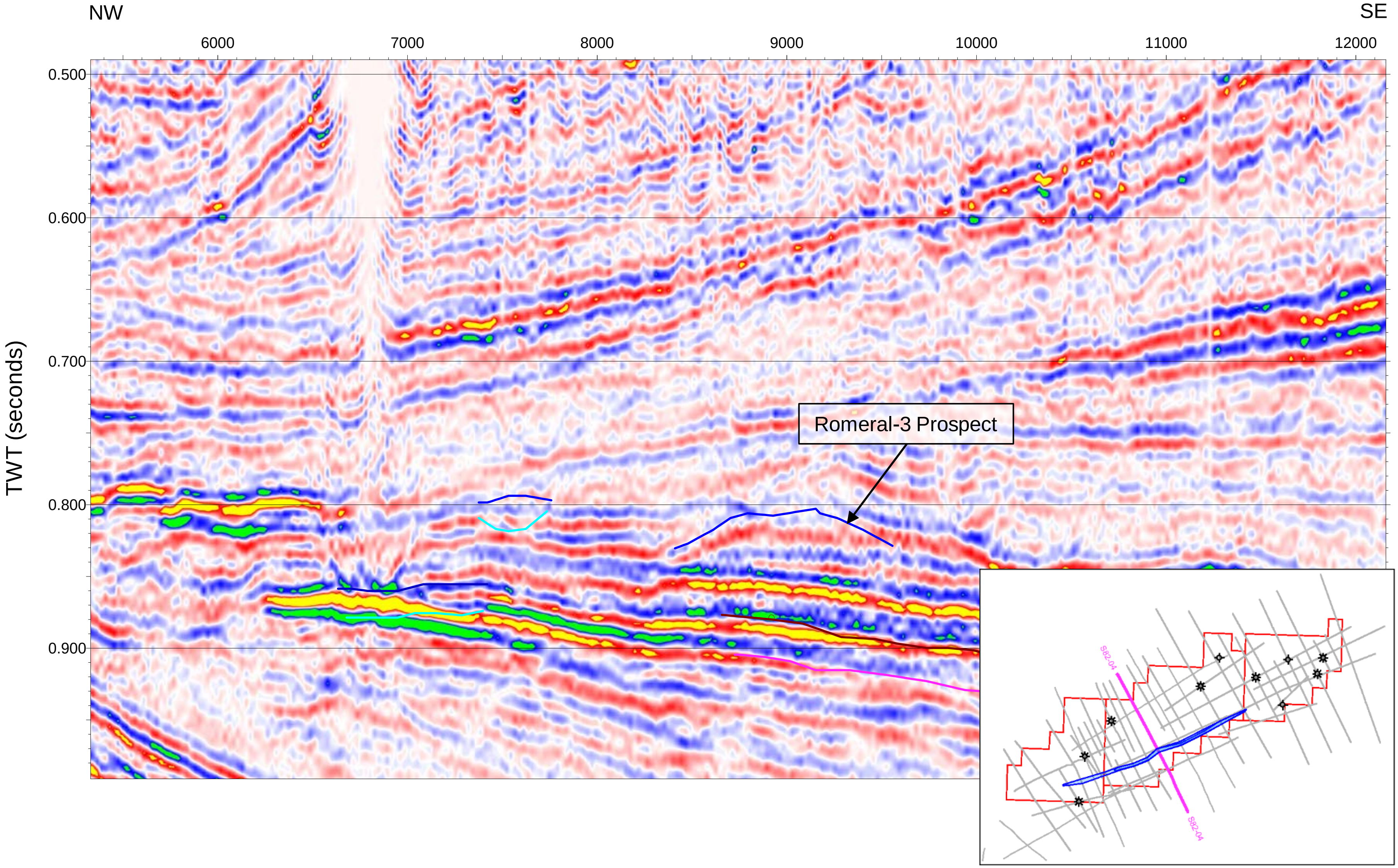


Figure 19

2-D Seismic Dip Line S83-114
Saltillo Prospect
El Romeral License Area, Onshore Southern Spain

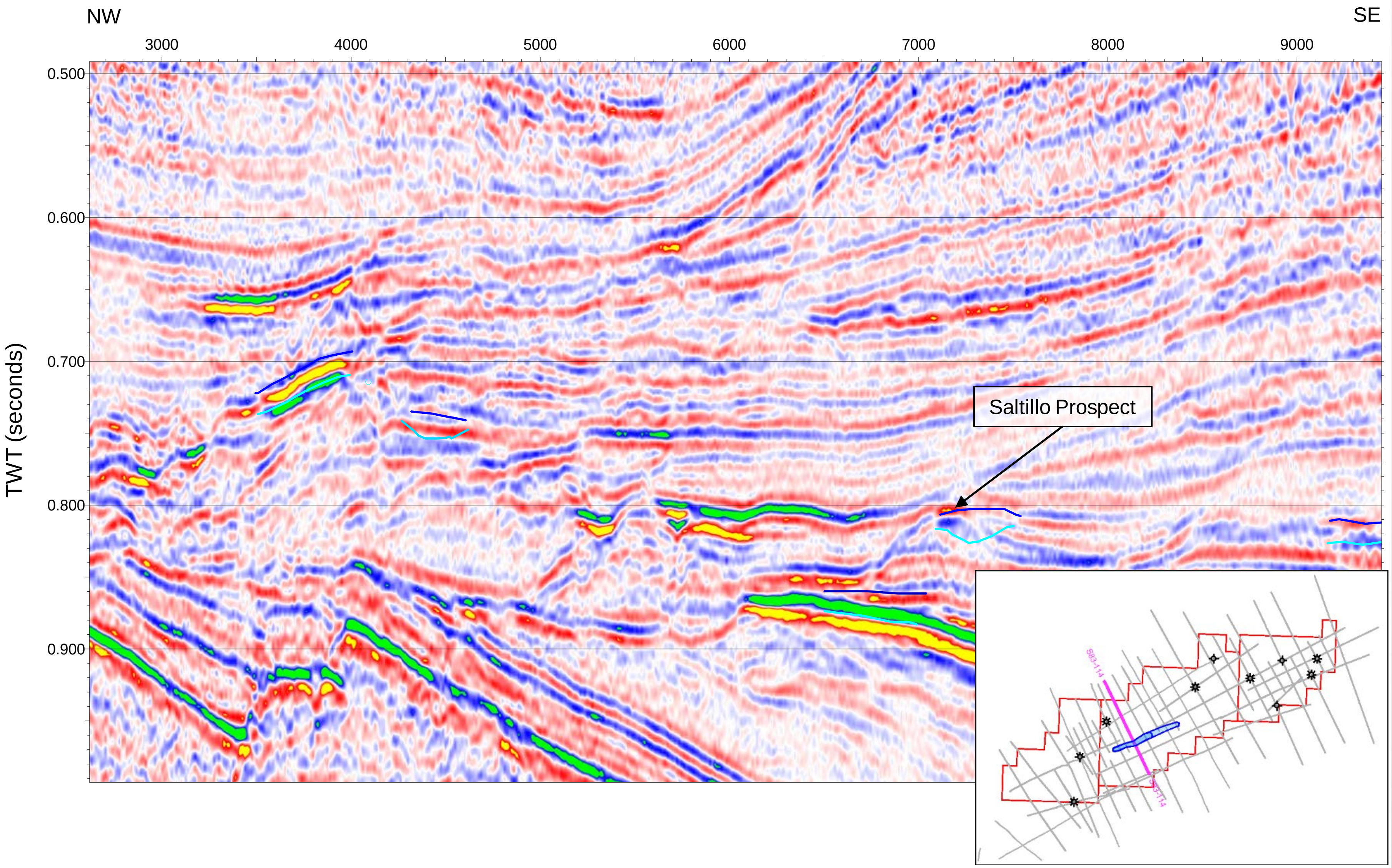


Figure 20

2-D Seismic Strike Line S85-01
San Pablo Prospect
El Romeral License Area, Onshore Southern Spain

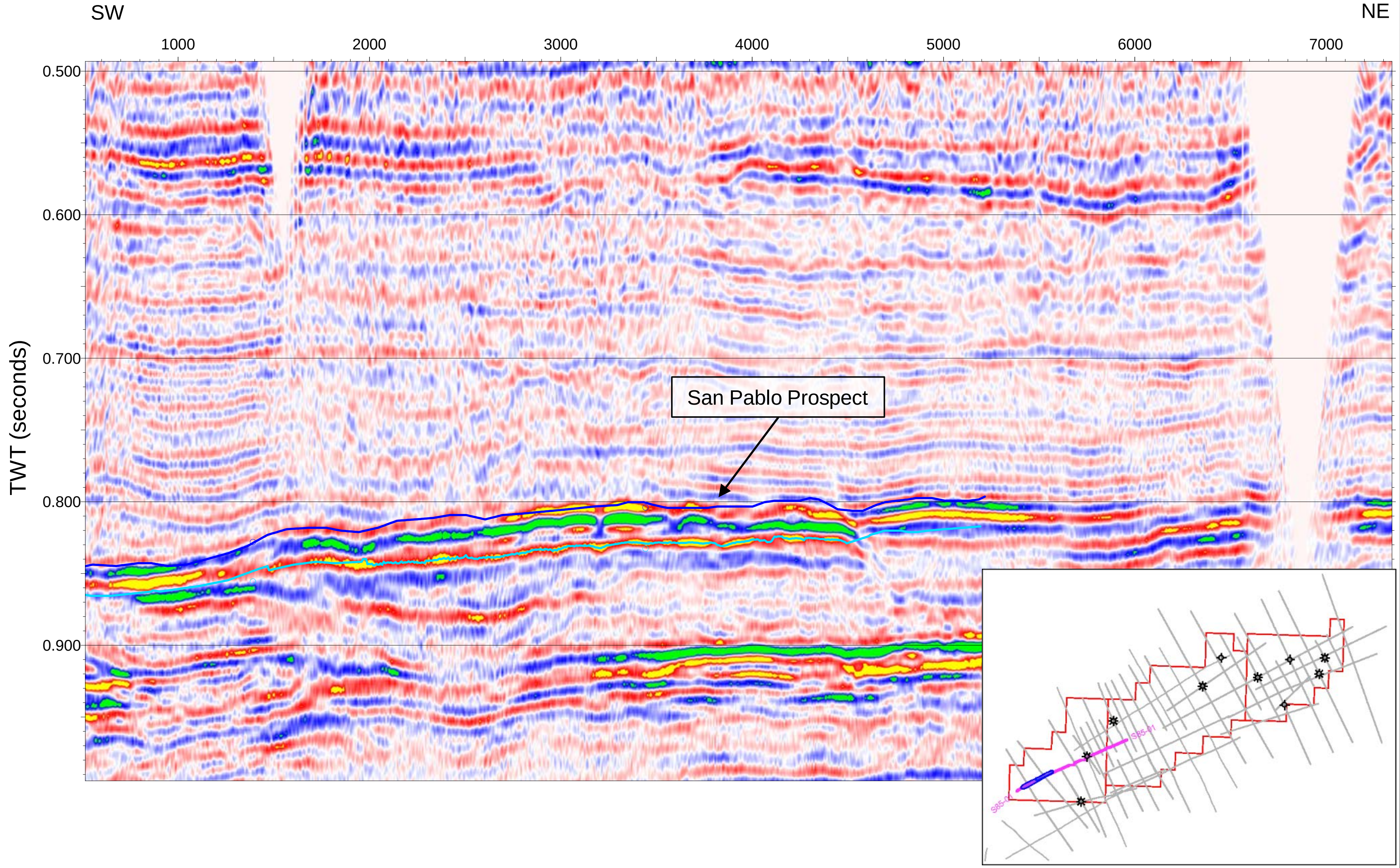
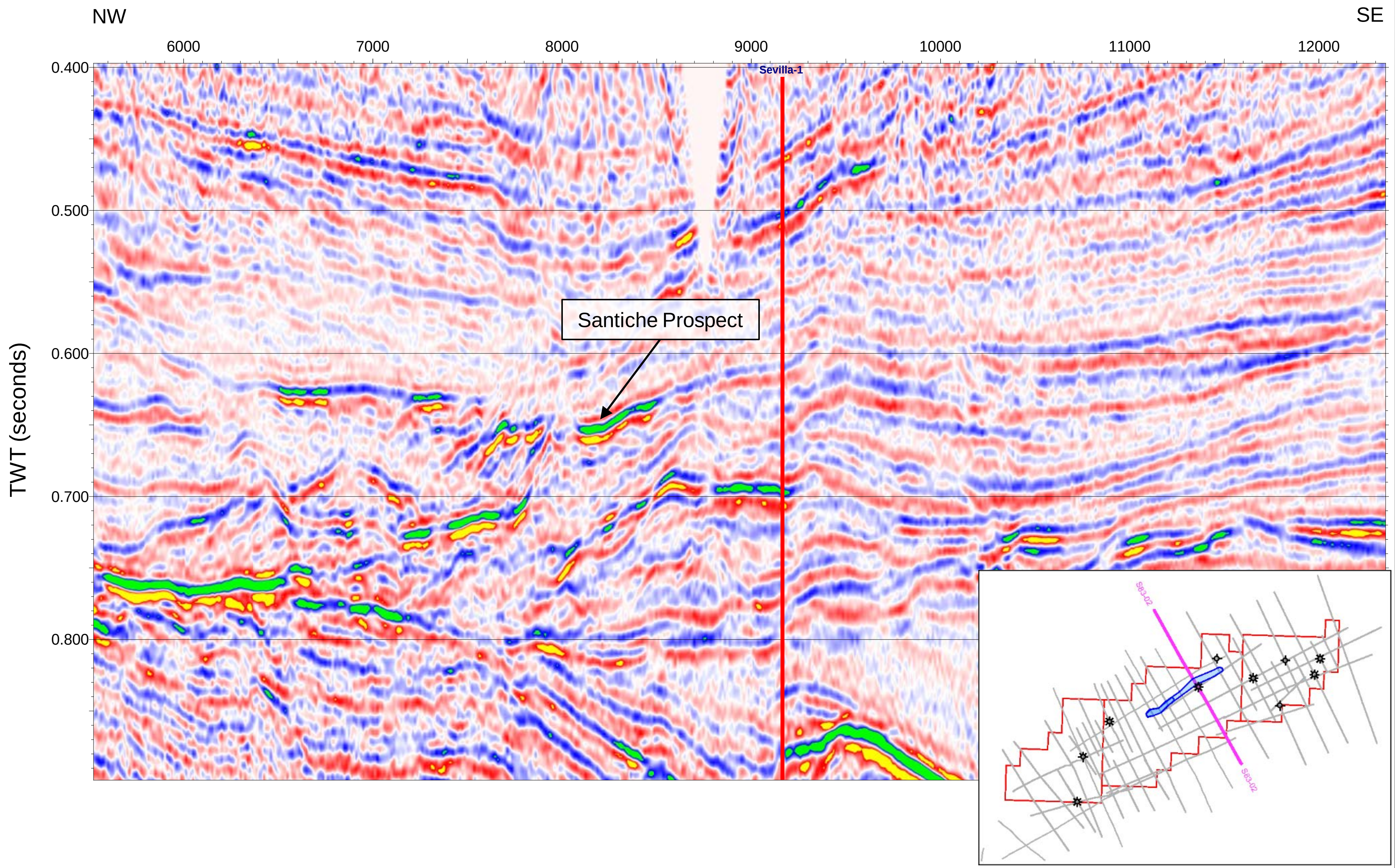


Figure 21

2-D Seismic Dip Line S83-02
Santiche Prospect
El Romeral License Area, Onshore Southern Spain



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