DECEMBER 2018

GLOBAL INSIGHTS

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The global market continues to explore for investments outside of the US with renewed excitement. Major operators are looking for low-risk propositions around the world with emphasis in South America and Continental Europe. Read this e-book to identify opportunities and lower your investment risks.

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1 Equinor Drilling Ahead inBrazilian Deepwater

Norwegian operator Equinor's focus on Brazilian deepwater exploration continued through September 2018 with the spud of a new appraisal well in the Carcara Field in the pre-salt Santos Basin. The appraisal is being drilled on the back of a possible commercial discovery on the Guanxuma prospect announced July. The company is currently producing around 65,000 barrels of oil per from the Peregrino Field in the Campos Basin but is targeting 300,000 to 500,000 a day from the country by 2030 with US$ 15 billion of investments planned.

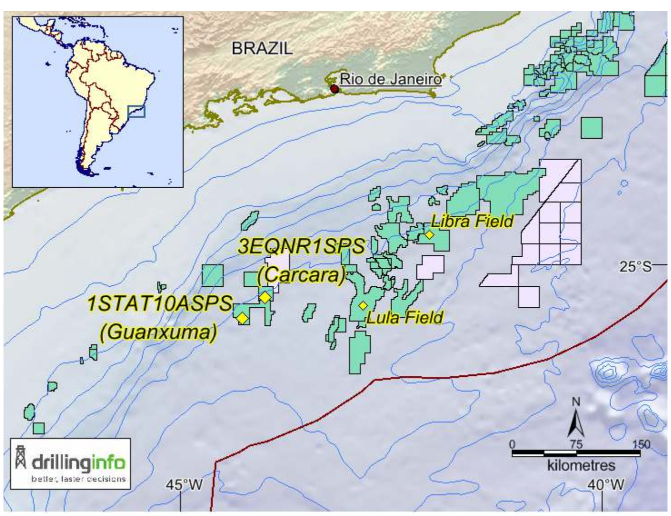


Figure 1 – Equinor Guanxuma & Carcara

Equinor, formerly Statoil, on 13 September 2018, spud the 3EQNR1SPS outpost well on the Norte de Carcara Block in the Santos Basin. The West Saturn rig is drilling the well in 2,052m of water. The well has a planned total depth of 6,669m and is called Carcara West based on its location to help define the western part of Carcara Field. Objectives of the well are assumed as the pre-salt Barra Velha Formation or the coquinas of the Itapema Formation. Equinor announced plans on 5 September 2018, to begin drilling on the Norte de Carcará Block by the end of 2018, after the drilling and testing phase on the Guanxuma sidetracks were finished. However, just eight days later the current outpost was spud on Norte de Carcara by the same rig being used for the Guanxuma program indicating that the sidetracks following the discovery may have been unsuccessful. The company received a license to drill up to five wells on the Norte de Carcara Block from Ibama in early September. These recently licensed wells can be added to the seven that have already been licensed in Carcará to make a possible 12 well drilling program for the field. The unification of the two blocks into a single field should be approved in 2019 or 2020, according to the Equinor senior VP. First oil is still scheduled for 2023 or 2024 but could be impacted by the final plans of Equinor to develop the Guanxuma discovery or not. The spud by Equinor of the first well in Norte de Carcara is also the first well drilled by the company or any company other than Petrobras, under the production sharing contract regime in Brazil. The Carcara Block is adjacent to Norte de Carcara, which was acquired in the second production sharing round in 2017.

In July 2018, Equinor announced the 1STAT10ASPS new field wildcat on the pre-salt BM-S-8 Block in the Santos Basin had discovered hydrocarbons, calling the discovery, "promising". The well on the Guanxuma prospect was spud on 29 April and was drilled to 6,600m with Seadrill's West Saturn drillship in 1,990m water depth. It is assumed to be suspended as a potential oil discovery since the rig began drilling a geologic sidetrack on 30 July, followed by a third well from the same surface location with the same planned total depth, indicating potential problems with the first sidetrack. Both sidetracks are now finished drilling and neither is yet on record as filing an oil or gas show report with the ANP which is mandatory if oil or gas shows are encountered. This could give credence to an unconfirmed rumor in the industry that the Guanxuma discovery was disappointing. Guanxuma had pre-drill estimates of 700 MMbo to 1.3 Bboe in recoverable reserves and is located on the other end of the BM-S-8 Block from the pre-salt Carcará Field, which is already estimated to have 2 Bboe recoverable. Equinor operates the block with 36.5% with partners ExxonMobil (36.5%), Petrogal (17%) and Barra Energia (10%). A unitization of the Carcará Block with the Norte de Carcará Block, which is currently undrilled but through seismic analysis is interpreted to include roughly half of the Carcara Field, is ultimately expected. Both Equinor and ExxonMobil are in the process of raising their stakes in the project to 40% before 2019, while Petrogal's interest will climb to 20% and Barra Energia will leave.

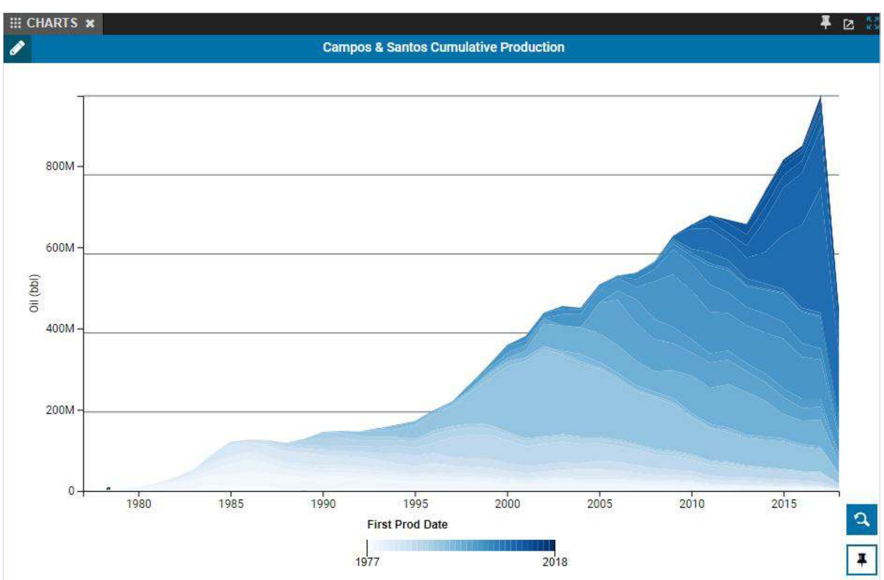
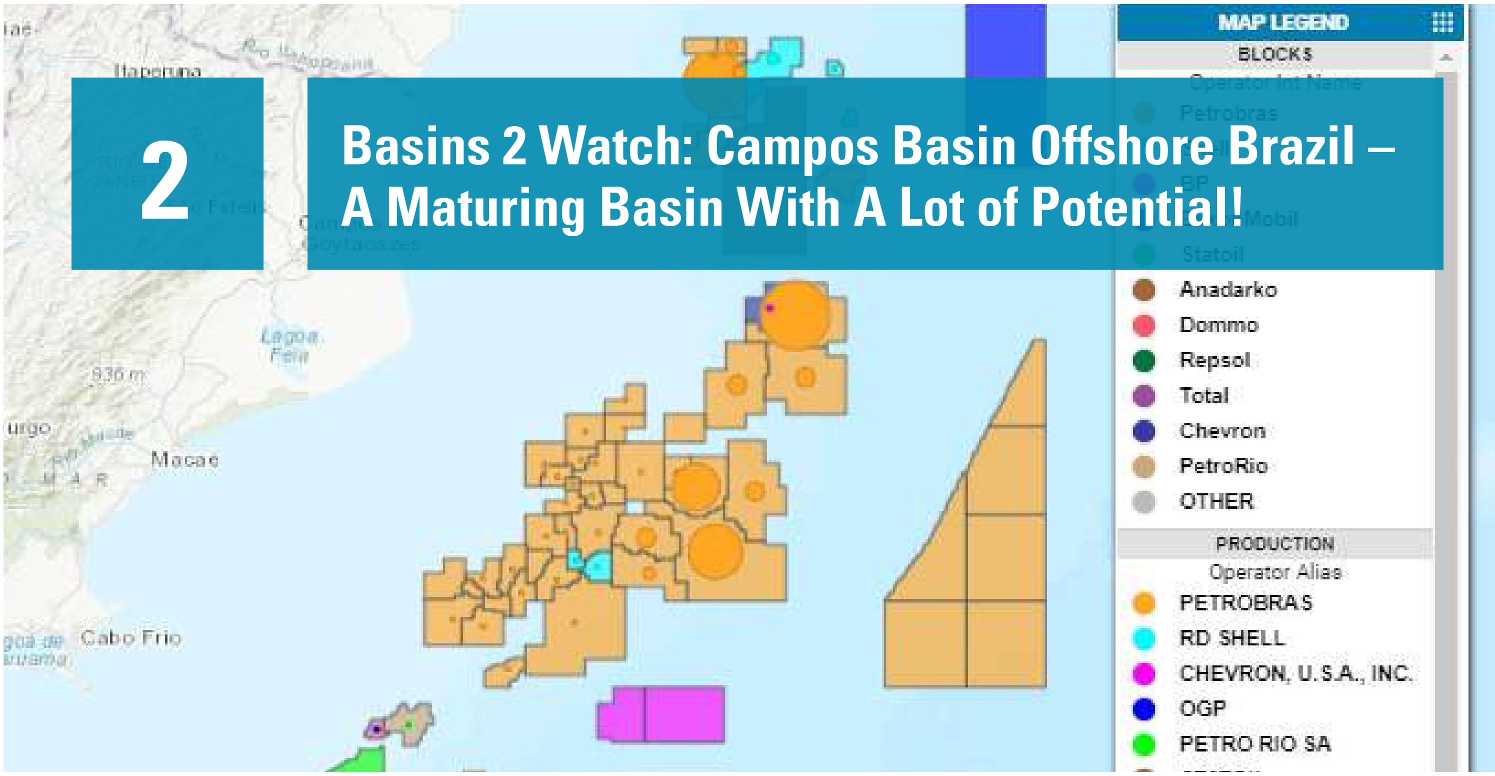


Figure 2 – Santos & Campos Basin production



2 Basins 2 Watch: Campos Basin Offshore Brazil – A Maturing Basin With A Lot of Potential!

The Campos Basin in offshore Brazil has been explored and produced since the 1980s, making it a relatively mature basin with a known working hydrocarbon system. Primarily Petrobras has been the dominant operator in the area exploring the post-salt resource. Resource potential in the Campos and Santos basins (includes only pre-salt) was published as 176 BBOE by a study conducted by the Federal University of Rio de Janeiro. A look at the current operator activity in the basin shows majors like Shell, BP, ExxonMobil and Equinor present in addition to Petrobras. After the late 1990s and the Brazil energy reform, Brazil and the Campos Basin were opened for operations and ownership to companies besides Petrobras.

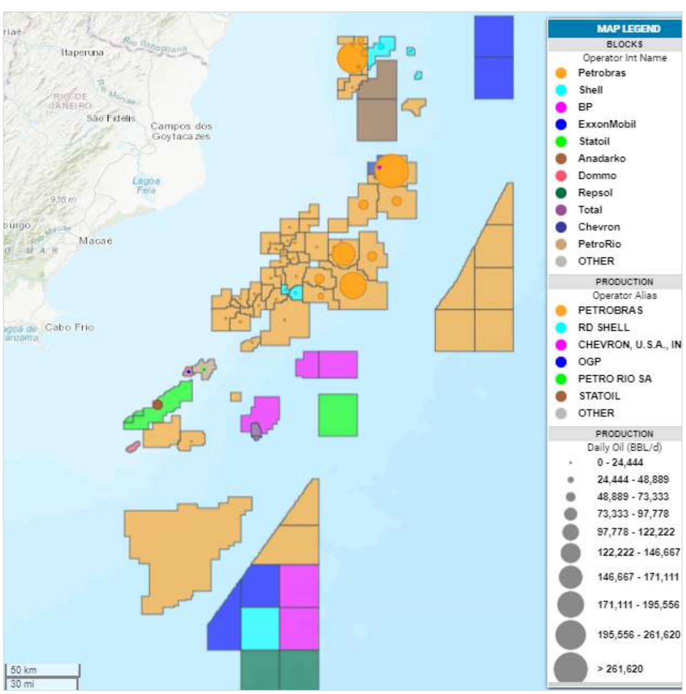


Figure 1: Map showing the current block operatorship as well as Daily Oil Production (BBL/D) from producing fields in the basin.

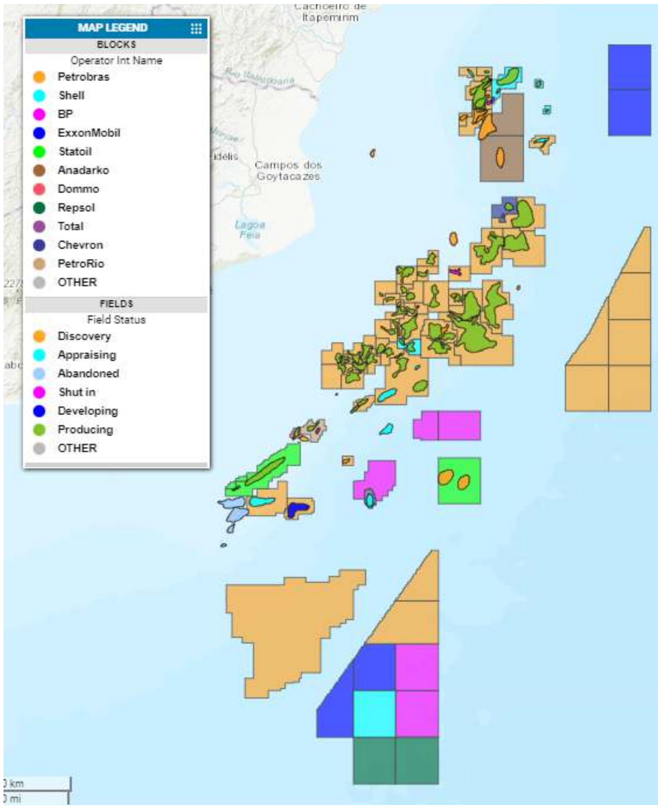


Figure 2 – Map showing the discovered fields in the Campos Basin. Many are actively producing, with a few currently being appraised and two that have recently been discovered.

Production

There are over 40 producing fields in the Campos Basin, primarily operated by Petrobras, with one being appraised by Shell and two recent discoveries by Equinor (Figure 2). The production is the basin has been declining at about 9% per year recently, so new fields coming online will be welcomed with underutilized infrastructure capacity by the basin (Figure 3). Activity has been primarily post-salt, but there is potential for secondary and tertiary recovery efforts to be implemented in the declining fields plus additional pre-salt exploration opportunities to fill the under-capacity infrastructure in the basin.

There is development and production activity in the Campos Basin as Petrobras is in the bid process and/or actively deploying FPSOs to three fields (Figure 4). Petrobras is in the bid process to deploy an FPSO with 100,000bo/d and 176 MMCFg/d capacity. The Jubarte Field has an interesting story, as it originally was six separate post-salt fields, each with estimated resources in the 100 MMBOE range. Today, 25 wells are producing from the pre-salt in the Campos Basin, with 14 of these in the Jubarte area producing over 180,000 bo/d.

Figure 3 – Block level production in the Campos Basin. Starting in 2008 there is a 9% decline/year in the basin.

The result of the large pre-salt discovery forced Petrobras to unitize all six separate fields into one field plus it kicked in a special participation tax, as the discovered resource is so large. In addition, Petrobras plans to deploy two new FPSOs to revitalize the Marlim Field production and its pre-salt component, and another FPSO is allocated for the pre-salt resource at the Albacora Field.

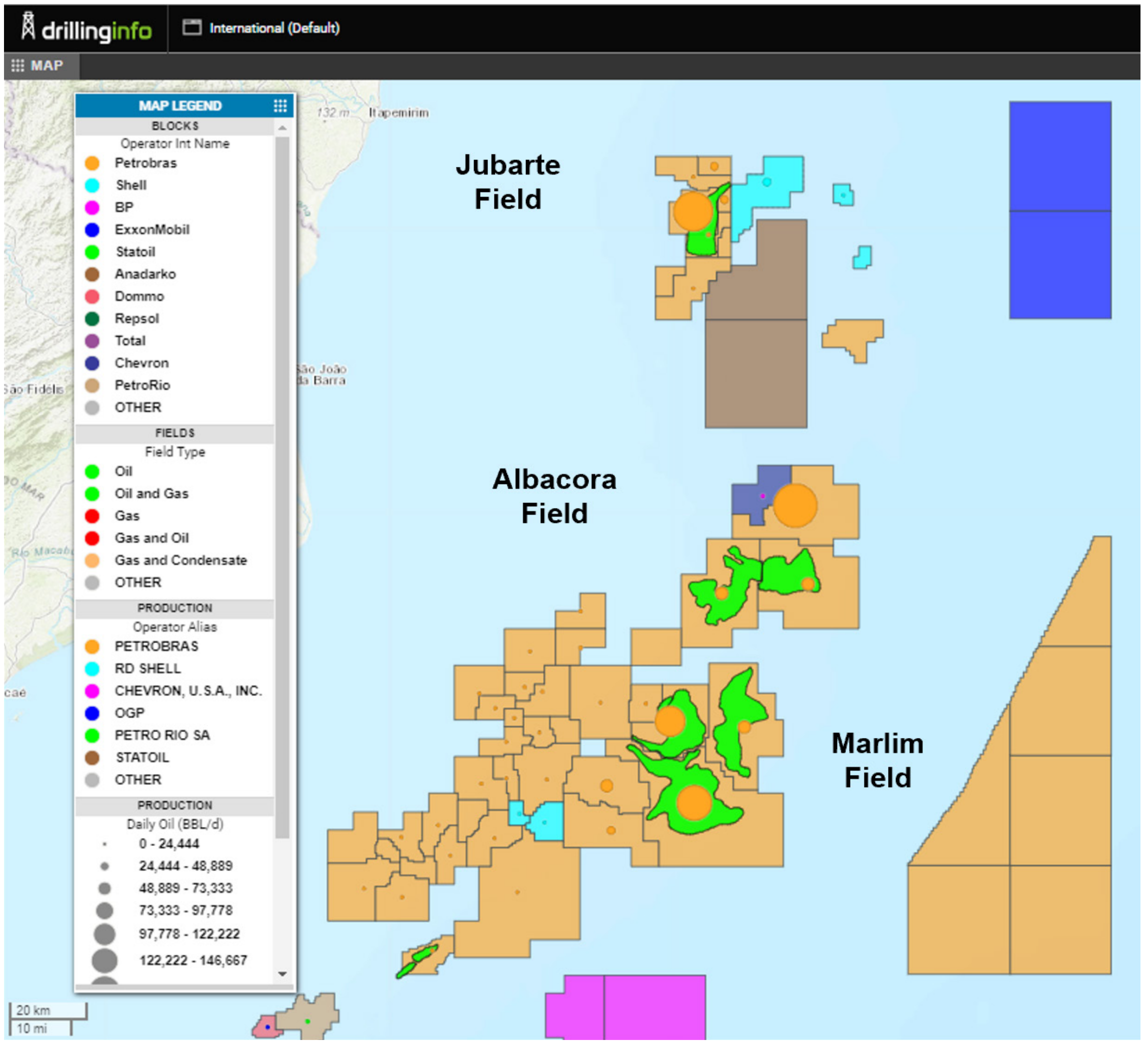


Figure 4 – Zoomed-in view of the Campos Basin where Petrobras has plans to deploy three FPSOs.

The most recent bid round, APN Round 15, concluded earlier this year with 47 blocks offered in offshore Brazil and 22 blocks awarded. All nine blocks covering 6,100 sq km offered in the Campos Basin were awarded (Figure 5). Participants of the Bid Round included: ExxonMobil, Shell, Petrobras, BP, Repsol and Qatar Petroleum. Partnerships between the participants were the key to this bid round to enable companies to put up the impressive bonuses and premiums. Block C-M-709 was awarded to Petrobras (operator 30%), Equinor (30%) and ExxonMobil (40%) with a bid of R$1.5 billion. Block C-M-657 was awarded to the same consortium with a signature bonus of R$2.128 billion. The highest bid in the round went to Block C-M-789. This block was won by ExxonMobil (operator 40%), Petrobras (30%) and Qatar Petroleum (30%), bidding a signature bonus of R$2.8248 billion and easily besting a partnership bid from Shell and Chevron.The result of the large pre-salt discovery forced Petrobras to unitize all six separate fields into one field plus it kicked in a special participation tax, as the discovered resource is so large. In addition, Petrobras plans to deploy two new FPSOs to revitalize the Marlim Field production and its pre-salt component, and another FPSO is allocated for the pre-salt resource at the Albacora Field.

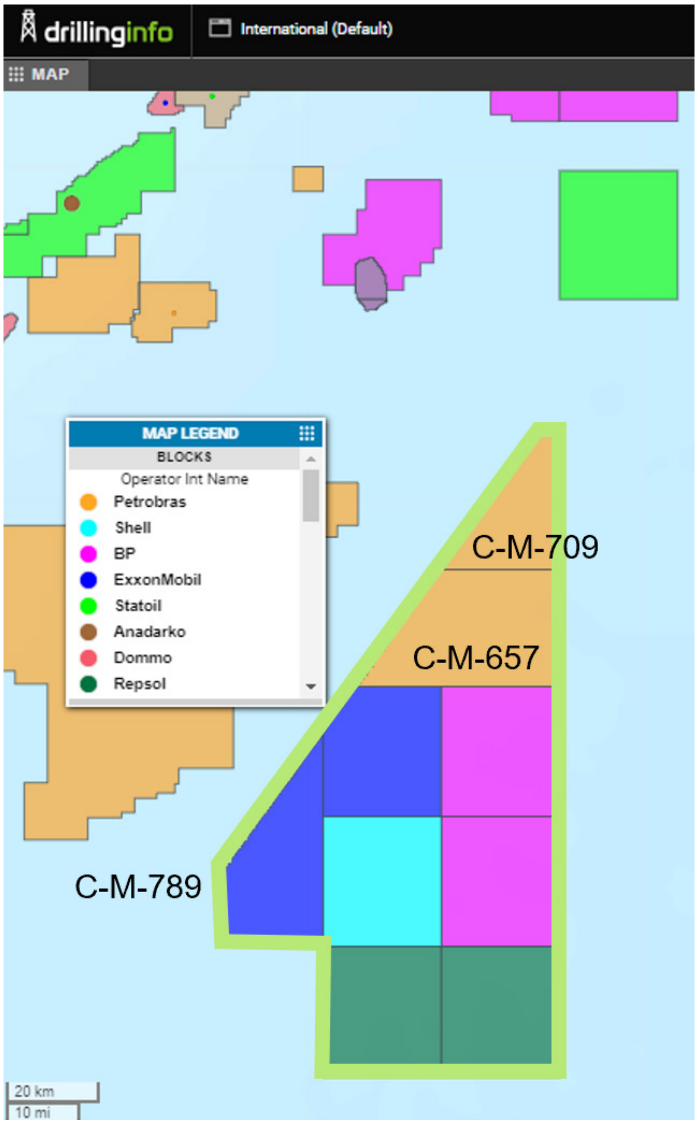


Figure 5 – Map highlighting the nine awarded blocks in the Campos APN Round 15 offering.

Bid Rounds and Future Activity

The most recent bid round, APN Round 15, concluded earlier this year with 47 blocks offered in offshore Brazil and 22 blocks awarded. All nine blocks covering 6,100 sq km offered in the Campos Basin were awarded (Figure 5). Participants of the Bid Round included: ExxonMobil, Shell, Petrobras, BP, Repsol and Qatar Petroleum. Partnerships between the participants were the key to this bid round to enable companies to put up the impressive bonuses and premiums. Block C-M-709 was awarded to Petrobras (operator 30%), Equinor (30%) and ExxonMobil (40%) with a bid of R$1.5 billion. Block C-M-657 was awarded to the same consortium with a signature bonus of R$2.128 billion. The highest bid in the round went to Block C-M-789. This block was won by ExxonMobil (operator 40%), Petrobras (30%) and Qatar Petroleum (30%), bidding a signature bonus of R$2.8248 billion and easily besting a partnership bid from Shell and Chevron.

With the conclusion of the last sale, what is the future for the Campos? There are multiple upcoming licensing rounds in June and September, plus the permanent cycle offer in the basin as well (that will not include the pre-salt – Figure 6). Also, with the improvement of technology to image through the 1-2 km salt layer in the basin, TGS was approved in March 2018 to shoot a 9500 sq km 3D seismic survey over the offered blocks in APN Round 16 in 2019.

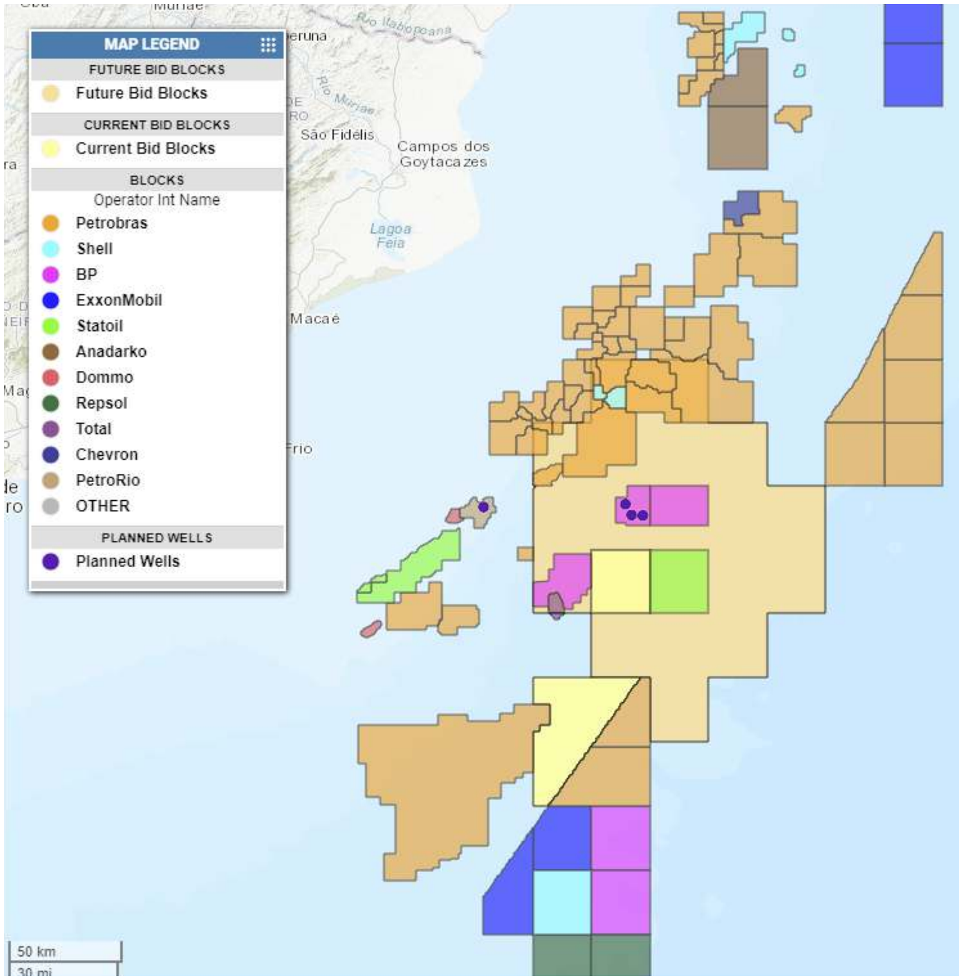
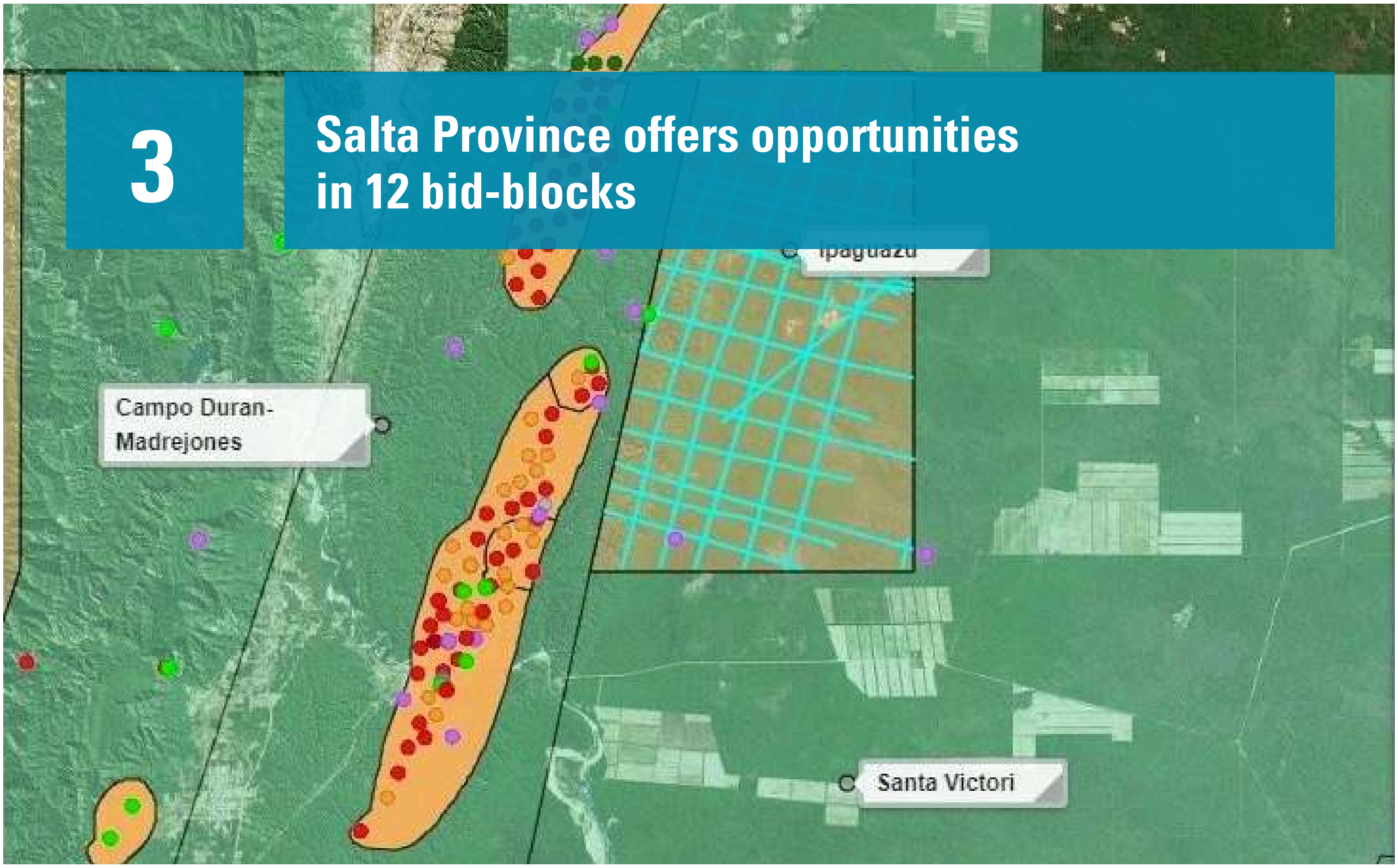


Figure 6 – Map showing the current operator blocks, planned wells, current and future bid rounds in the Campos Basin.

In conclusion, with the upcoming licensing rounds offering blocks in both the Campos and Santos basins, the Campos Basin might be a better value for a few reasons:

- More infrastructure in place in the Campos versus the Santos
- Both basins have pre-salt prospects, but the Campos has post-salt reserves that are easier and cheaper to drill
- Possibility of more favorable concession regime in the Campos Basin
- Giant fields maturing or declining but very little done for secondary recovery on most of them

Based on some of the above-mentioned factors, the Campos Basin has commanded high prices on the recent rounds, meaning you need to come ready with deep pockets.



3 Salta Province offers opportunities in 12 bid-blocks

Argentina's Salta Province government presented to the Houston oil & gas community the Salta Province Bid Round 2018 offering 12 blocks for exploration and eventual development. An additional three blocks will also be tendered later this year. A small group attended the event but among the companies were majors ExxonMobil and Chevron. Neither company has been involved in the area before signaling that Salta could become a hot area for exploration in South America. The offered areas to be included in the current launch are: 9790 sq km Algarrobal, 7,676 sq km Guayacan, 184 sq km Ipaguazu, 1,766 sq km Las Canitas, , 9,810 sq km Ojo de Agua, 4,052 sq km Pichanal, 1,176 sq km Pocoy, 7,232 sq km San Ignacio, 381 sq km San Telmo, 6,444 sq km Santa Rosa, 8,546 sq km Tolar Grande and 245 sq km Yariguarenda. The areas to be offered in July are 2,884 sq km San Carlos, 6.3 sq km Cuchuma and 2 sq km Lumbrera.

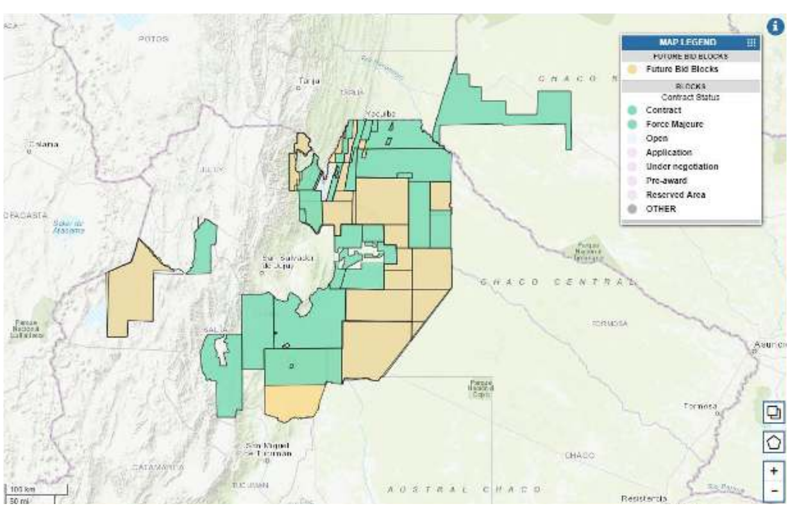
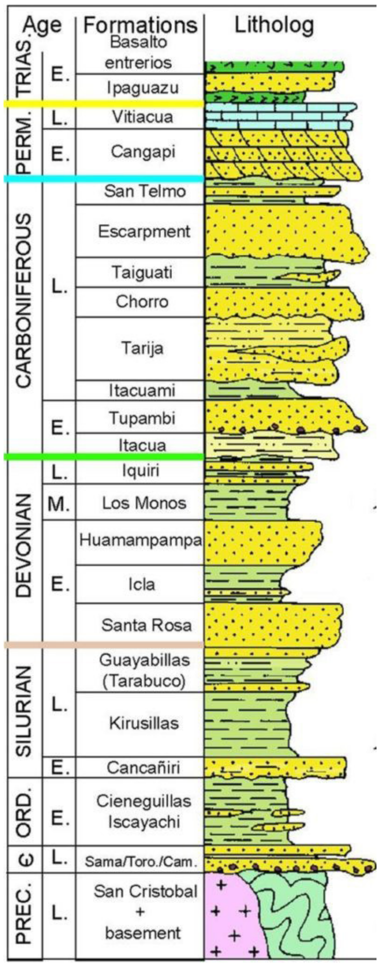


Figure 1 – Salta bid blocks and licensed acreage

With more than 80 years of oil and gas activity, the northwestern province of Salta was for decades the second highest producer in Argentina but natural reservoir declines from long-term production and also low natural gas prices the absence of wellhead gas pricing policies have slowly led to Salta losing its position.



A recent analysis of daily production shows Salta production at about 5,000 bo/d and 233 MMcg/d from 65 wells. Total proven reserves were published in 2016 as 28.21 MMbo and 714.51 Bcfg. The main producing prospects and horizons in Salta are the Silurian-Devonian Huamampampa, Icla and Santa Rosa formations as well as interesting future possible shale prospects for the Los Monos Formation, seen previously as a source rock but where interesting results have been recorded on the Yacuy 1001 and Ramos 1004 wells. The San Telmo, Las Penas, Tarija, Tupambi and Cretaceous Yacoraite formations are among the recognized productive horizons and targets in the province and Paleozoic prospects are deep but hold high productive potential for both oil and natural gas. The top four producing fields in the province are Ramos, Acambuco, Aguarague and San Antonio Sur.

Figure 2 – Needs description

Figure 3 – Icla fm type production curve

Figure 4 – Yacoraite fm type curve

Since 2015 the provincial government has started an initiative to improve conditions for exploration and production in Salta. A new law was invoked for a special promotional regime to stimulate investments, including tax exemptions on equipment acquisition and possible reductions in royalties, especially for high risk projects were addressed by the law. Provincial hydrocarbon data has been catalogued and organized to accommodate the exploratory plan of Salta created in 2016. The main objective was to make the data accessible to better identify, qualify and quantify resources to promote future investments in the province. Detailed technical data on historical exploration wells, hundreds of seismic lines and additional is now accessible for potential bidders to analyze available blocks.

The most interesting areas to be offered in the upcoming round may be the ones with existing discoveries and possibly high potential. This includes the Guayacan, Ipaguazu, Yariguarenda and Las Canitas blocks. This blog will take a quick look at a couple of these.

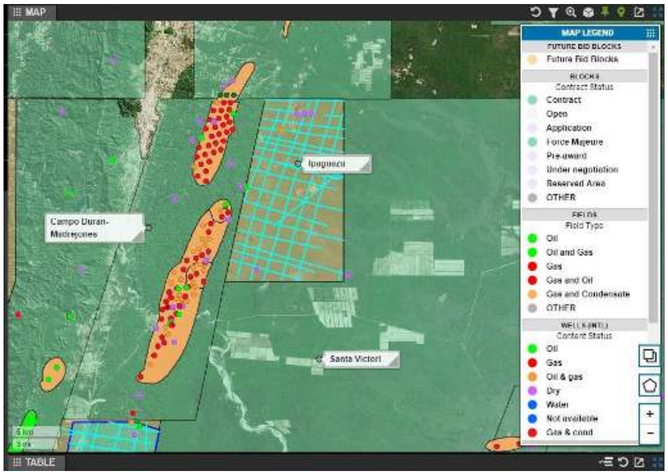


Figure 5 – Ipaguazu block

This 183 sq km license It is in the prolific Tarija Basin, between the Campo Duran-Madrejones area currently operated by Tecpetrol, and the Santa Victoria block (Madalena Energy). Tecpetrol in 2017 presented an US$ 30 million investment plan for Sierra de Aguarague. The license was awarded in 1990 and the partners have since been granted a 10 year extension of the contract which now expires in 2025. Geological targets are the Carboniferous Tupambi Formation at depths of around 3,800m and the Devonian.

The Ipaguazu anticline is separated from the Madrejones by a deep syncline which leads to hydrodynamic pressures on both sides. The Tupambi Formation seems to draw the most geological interest in the area. Six wells have been drilled on the block with the most notable being the Ipaguazu x-1 which tested in 1981 about 918 bo/d and 10 MMcfg/d from the Tupambi Formation. The sweet spot is projected to be about 3,000m deep with the observation of paleo channels in available 2D seismic lines.

The Devonian play is represented by the Huamampampa and Santa Rosa formations. These formations were not reached by the Ipaguazu x-1 but the play has been highly productive in the neighboring Aguaragua, San Pedrito and Ramos fields.

Future exploration work like reprocessing 2D lines, surface geochemistry, additional seismic acquisition and new drilling plans are expected to be worthwhile exploration investments for the block.

This block is also in the Tarija basin, close to Bolivia and adjacent to the west with the Acambuco I Block operated by Pan American Energy and to the east of Madalena Energy's Santa Victoria Block. Chinese operator, JHP operates south of this license with the Tartagal Oriental Block. Six wells have been drilled historically in this area with two of them being successful. The Nacatimbay x-1001 and the Tartagal Oriental x-1001 tested oil and gas from the Las Penas and Tupambi Mississipian sandstones. The approximate depth of the objectives was 3,800m. The Nacatimbay well was drilled in the southern portion of the structural alignment of the Campo Duran, Madrejones and Icua fields. The Nacatimbay x-1001 tested gas and condensate in 1995 with a TD of 4,159m. The southern part of the area structures shows emergent faults from the Los Monos Formation (source rock and potential unconventional target).

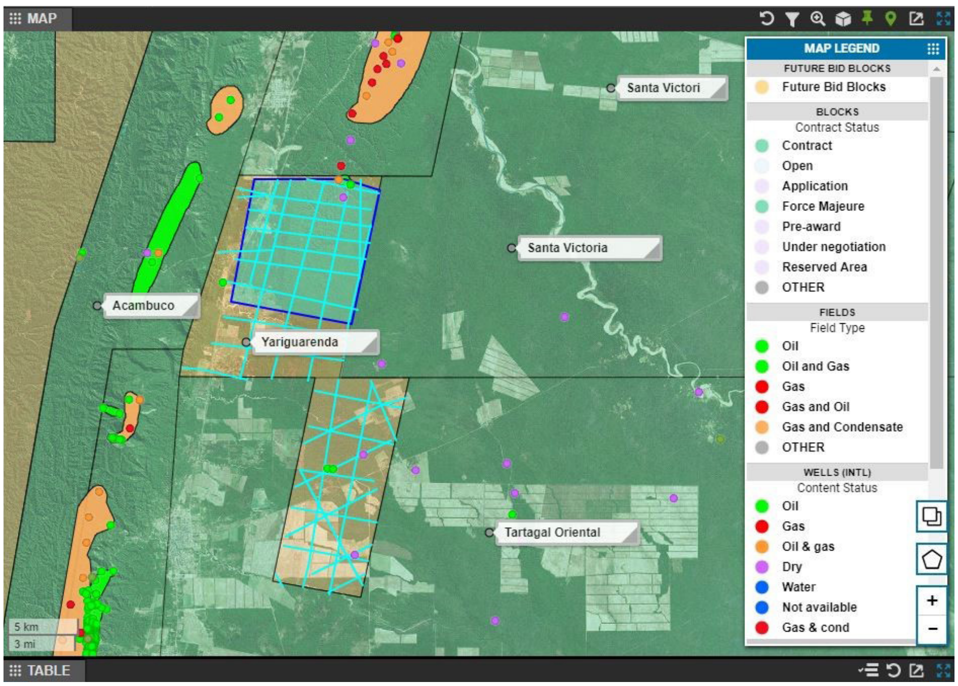


Figure 6 – Yariguarenda block

The exploration challenges include assessing the Devonian Huamampampa and Santa Rosa formations, which produce oil and gas in neighboring Madrejones and Campo Duran.

The Tertiary Complejo Petrolifero Rio Pescado is also an interesting target to investigate, as well as the Carboniferous San Telmo Formation.

The expected work programs in Yariguarenda includes reprocessing existing 2D seismic, perform surface geochemistry and acquisition of some new 3D seismic to delineate the Tupambi reservoir in the southern area of the block. Deeper structural assessment and additional drilling is also expected if justified by these studies.

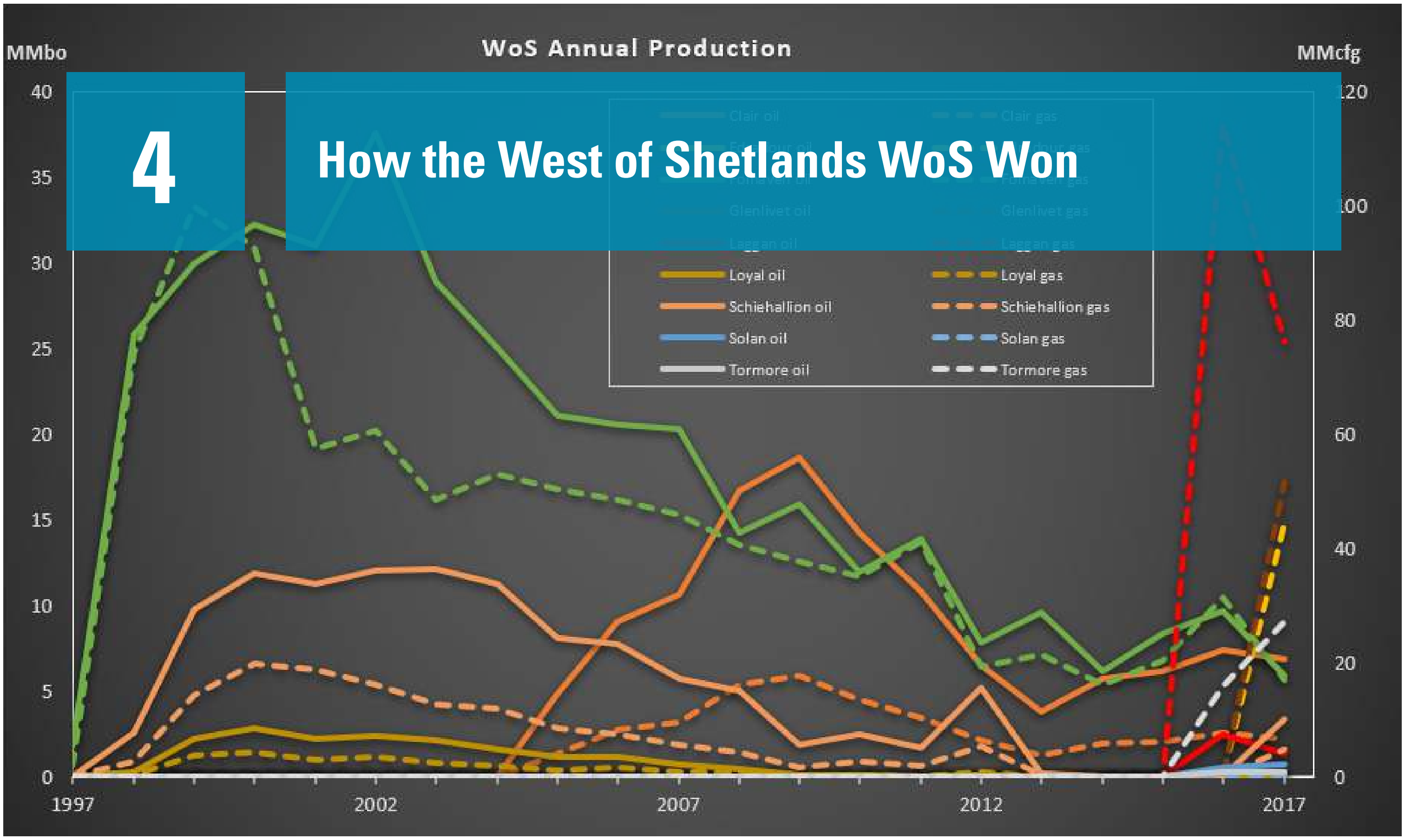
General exploration overview

Although there are some discoveries with interesting results, the Salta bidding blocks require extensive and intensive additional exploration work to determine profitability of oil and gas development. Further analysis is needed of existing technical information to use for exploration of deeper horizons also. The Tarija and Oran-Olmedo Basin in Argentina need further exploration and analysis of the petroleum systems and play definition in order to better identify possible sweet spots. The gas window, especially in the Carboniferous and Devonian plays is a great opportunity to invest in these blocks.

Additionally, the Los Monos Formation in its sandstone facies has been mentioned as an interesting unconventional tight gas play especially for the Aguarague-Ramos anticline. Porosity is low but gas saturation very high in its psamitic intercalations. The Salta province prospects in the Tarija basin are very linked to Bolivia gas fields in that basin with the reasonable hopes that some of the high producing wells and multi-Tcf fields can also be found on the Argentine sine of the border in Salta.

However, drilling and operating costs in Salta are currently higher than those in Neuquen for example due to more difficult drilling conditions, as well as the deeper objectives averaging between 3,800-4,200m and lack of economies of scale that now exist in Neuquen. The higher costs can be compensated by much higher volumes per well though especially with natural gas.

Improvements in government pricing and tax policy to promote industry activity in recent years, like an agreement being discussed with the Federal Government to apply to Salta the special gas pricing promotion plan now active for the Neuquen and Austral basin could provide the missing piece to help to revive the Salta Province to reach its full potential in hydrocarbons.



4 How the West of Shetlands WoS Won

The UK West of Shetlands (WoS) doesn't often take the limelight as a frontier area that is becoming a developing hub, but here are some reasons it should: Movers and shakers like Total, BP and Premier operate producing fields in the area; Chevron had been working to towards and FID for Rosebank, and Equinor will soon take over the reins; and Siccar Point and Nexen have exploration and appraisal drilling planned for the near future.

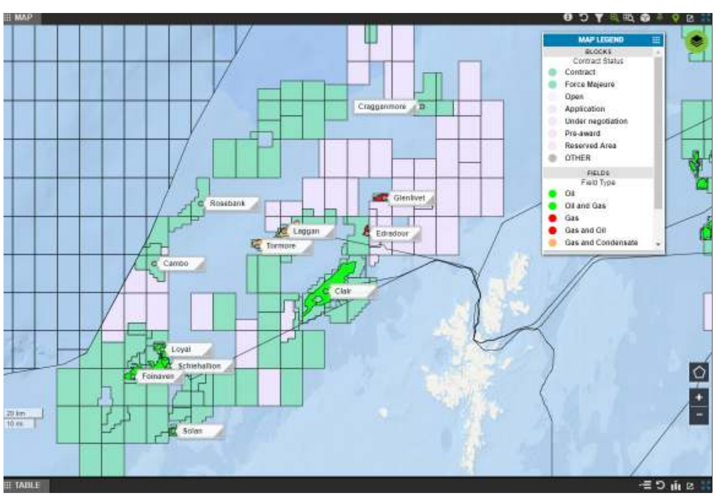


Figure 1 – WOS fields

Production

BP commenced production in the basin at Foinaven Field in 1997, and soon added Loyal and Schiehallion; all three fields produce oil via FPSO, and gas via pipeline to Sullom Voe terminal. Since then, Clair, Greater Laggan Area, and Solan have all been brought to production, with Clair Ridge set to join later this year.

Development	Operator	Recoverable reserves	Max production	Reservoir	Discovered	Onstream
Foinaven	BP	380 Mmbo & 230 Bfcg	110,000 boe/d	Palaeocene Vaila	1992	1997
Schiehallion & Loyal	BP	378 Mmbo & 158 Bcfg	130,000 boe/d	Palaeocene Vaila	1993	1998
Clair Phase 1	BP	300 Mmboe	54,000 boe/d	Devonian to Carboniferous	1977	2005
Laggan-Tormore	Total	132 Mmboe	90,000 boe/d	Palaeocene Vaila	1986	2016
Solan	Premier	40 Mmbo	25,000 bo/d	Jurassic Rona	1991	2016
Schiehallion redevelopment	BP	450 Mmboe	130,000 boe/d	Palaeocene Vaila	1993	2017
Glenlivet & Edradour	Total	65 Mmboe	56,000 boe/d	Vaila & Cretaceous Albian	2009	2017
Clair Ridge (due Q4 2018)	BP	640 Mmboe	120,000 boe/d	Devonian to Carboniferous	1977	2018

Figure 2 – WOS field discovery to production

To date, the basin has produced over 0.5 Bbo and 0.6 Tcfg, but the area is challenging due to the remoteness, harsh weather, and water depths which reach over 1,000m towards the UK-Faroe Islands border. The progression from discovery to production (Fig. 1.) has often been drawn out; Laggan took 30 years to bring online, Clair 28 years, and Solan 25 years. The delays at Clair can at least partly be explained by the difficult, fractured reservoir, and BP's focus on Foinaven, Schiehallion and Loyal. The Greater Laggan Area development required significant investment to construct the Shetland gas processing plant and install a 142 km oil and gas export pipeline, one of the world's longest deepwater tie-backs to shore. The Total-led partnership invested US$5.4 billion in the project but lead contractor Petrofac still lost over US$ 400 million on the project. Appraisal at Solan was initially unsuccessful, until Chrysaor obtained better drilling results in 2007 and then sold the field onto Premier.

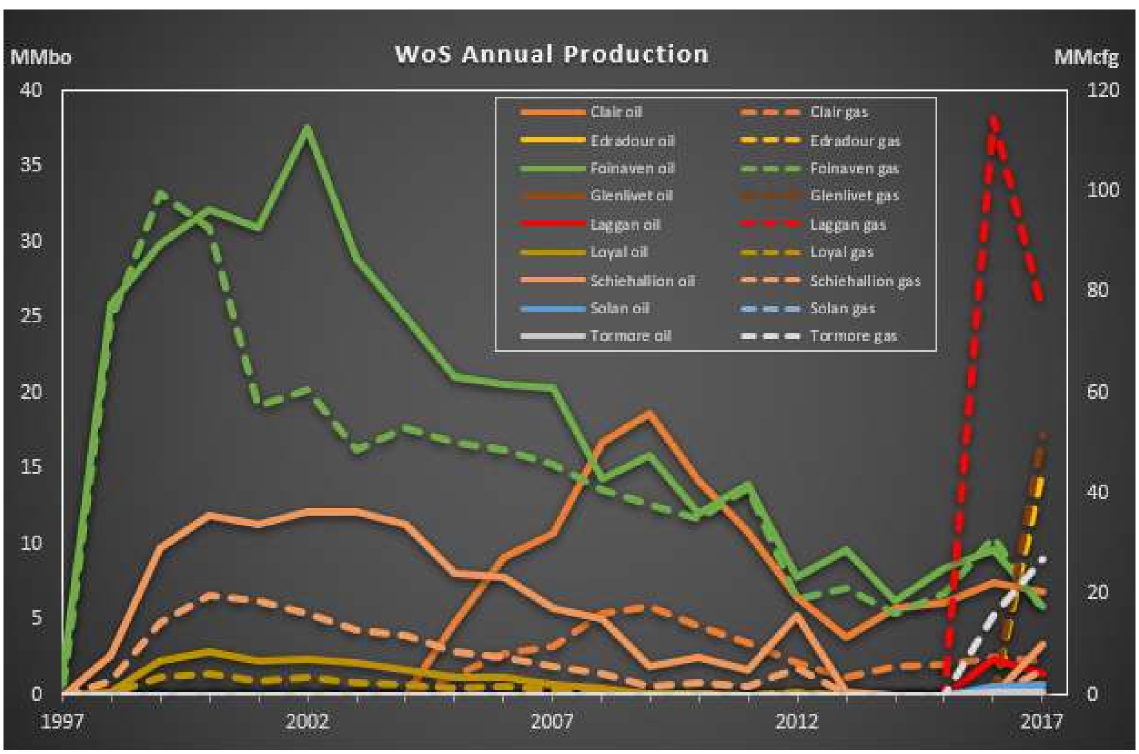


Figure 3 – WOS Annual Production

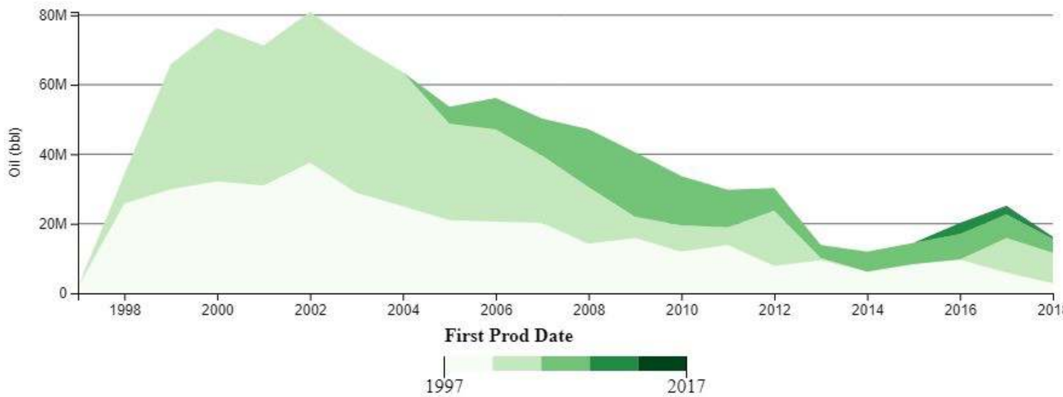


Figure 4 – WOS Comparative Cumulative Production Oil

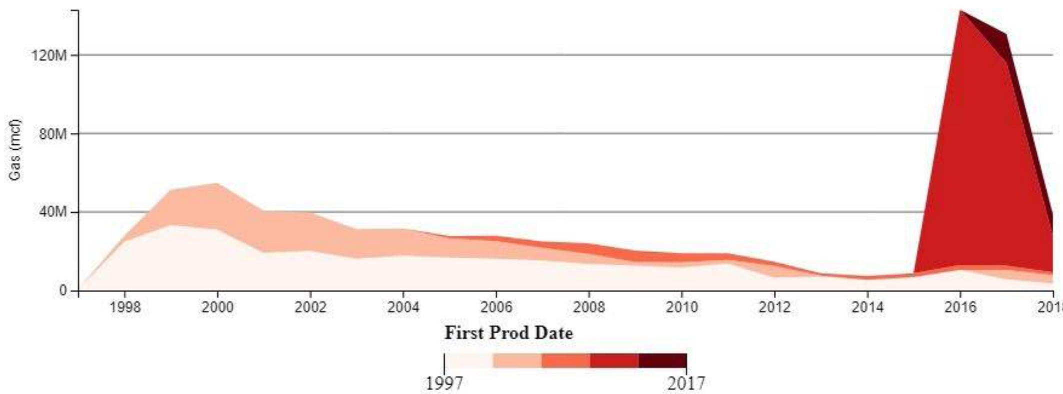


Figure 5 – WOS Comparative Cumulative Production Gas

Ongoing development, exploration & appraisal

What you will likely have heard a lot about, is Hurricane Energy's 100% owned early production system at the Lancaster fractured basement field due to come onstream via FPSO at the end of 2020, with estimated resources exceeding 200MMbo. Before that, BP intends to commence output from Clair Ridge, due online this year, and expected to produce until 2050. Elsewhere, Equinor is acquiring Chevron's operator share of Rosebank discovery with 2P reserves of 125-150 MMboe in Flett Formation. Chevron had been working towards FID on the field, with development costs of US$ 7 billion indicated in 2017.

Siccar Point acquired OMV UK at the beginning of 2017, including the Cambo discovery in Palaeocene Flett Formation. Alongside new partner Shell, it was appraised during summer 2018, and Cambo resources are estimated at 177 MMbo and 109 Bcfg. And Total made the most recent discovery in the basin with the Glendronach NFW in Q2/Q3 2018, estimated to hold 1 Tcfg in Early Cretaceous reservoir (42m net pay), drilled from the Edradour platform location, and likely to be developed as part of the Grater Laggan Area.

Planned exploration and appraisal

Looking ahead, Nexen and partner INEOS plan to appraise Cragganmore discovery in Palaeocene Vaila sands during Q4 2018. Siccar Point intends to drill Lyon and Blackrock prospects in 2019. Lyon was scheduled for 2018 but delays at the WoS Cambo appraisal well pushed the drilling into winter 2018/19. Lyon has estimated 1-3 Tcfg recoverable in Flett sandstones which could justify a stand-alone gas hub development.

Spirit Energy, the Centrica and Bayerngas Norge joint venture, agreed to farm into Hurricane's fractured basement play for 50%, and later operatorship in Lincoln discovery and Warwick prospect in September 2018 for full carry on a 2019 planned drilling campaign of two horizontal exploration sidetracks on the Warwick prospect and one appraisal horizontal sidetrack at Lincoln, plus partial carry of Hurricane's costs of a resultant field development.

Possibilities

The WoS has benefited from the combination of new companies backed by investment and established supermajors working together. The UK 30th round, targeting frontier areas saw awards announced in May 2018 where companies producing and exploring in the WoS picked up the acreage adjacent to their existing licences. In contrast the Faroe Islands 4th Exploration Round in 2017 across the border had its sole application for acreage withdraw post-closing of the round. Overall, development in WoS is looking pretty attractive if you're willing to put up the capital. The basin will likely see a continued moderately slow build-up of development that will allow small discoveries to be profitable, experience more exploration, and hence be an active region for decades to come.