

Extracting More From Less –The Development of the Noel Cadomin Resource Play

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Summary

A holistic multidiscipline effort was applied to identify the resource opportunity, best well design and optimal well layout for the development of the Noel Cadomin resource play on Apache leasehold. The implementation of appropriate drilling and completion strategies was guided by scenario-studies using a well-calibrated reservoir model. This resulted in economic gas production in thirty high-rate horizontal wells, from ten microdarcy reservoir, and plans to drill another ninety laterals to complete full-field development. Appraisal and development drilling in the Apache Noel field has resulted in gas production exceeding 100 mmcf/d. Well results are sufficiently predictable that tie-in routinely begins before completion activities, and without a production test.

Introduction

The Noel asset is located northwest of Grande Prairie, in Northeast British Columbia. Gas trapped in the Cretaceous Cadomin Formation is part of a regional basin-centered gas deposit colloquially termed the “Deep Basin”. The Cadomin Formation at Noel occurs as a twenty-meter thick, extensive, high-net-to-gross conglomerate that was deposited in a braid plain environment. The conglomerate consists of chert pebbles and a lithic sandstone matrix, with quartz and kaolinite cement. Deep burial has caused substantial reduction in Cadomin reservoir properties. The low three-percent porosity is primarily due to compaction and the development of quartz overgrowths, and also the presence of chert pebbles, which have no effective porosity. All the effective reservoir porosity of the Cadomin conglomerate in the Noel area occurs in the sand matrix.

Initial production attempts in Noel were made using fracture-stimulated vertical wells. Given the low matrix permeability, productivity was insufficient to drain the reserves or to be economically viable. Subsequently, the development team focused on horizontal wells and fracture technology to unlock the gas reserves.

Methodology

The Noel Cadomin reservoir evaluation incorporated extensive surveillance data from vertical and horizontal wells. Wide-spaced vertical wells supplied the basic reservoir description control points, with standard core, wireline log, flow-test and production data. Special data sets were captured in a few key wells, including pressure-fall-off tests, mini-fracs, cross-borehole seismic tomography, microseismic

mapping, and wellbore temperature logs. This vertical dataset provided key permeability, reservoir stress and frac-height data, which could not be reliably obtained from horizontal wells, and was necessary to optimize the horizontal well design. In the horizontal wells, production logging, camera data and additional microseismic mapping was captured, to complete the characterization of the fracture stimulation.

All available data were integrated to create a geologically realistic static reservoir description. Log and core data were integrated to determine reliable reservoir porosity and permeability ranges. The determination of accurate core porosity, for integration with log data, required additional core cleaning, and measurements at reservoir stress conditions. Water saturation data was captured from native state core. This was compared to Archie saturations calculated using electrical properties and water resistivity (R_w) from core measurement, and public-domain fluid resistivity maps. The resulting saturation data showed a strong predictive relationship to reservoir porosity. Likewise, a simple transform to calculate effective-permeability from porosity was achieved by calculating effective permeability from absolute core permeability and water saturation data, using a modified Corey equation. Porosity and tomography data were analyzed from both horizontal and vertical wells to characterize the geological variance. This provided guidance to generate geostatistical realizations of reservoir properties that matched the appearance expected in braid plain deposits.

From logs and core analysis it has been determined that the average reservoir properties are:

Porosity: 3.2 %

Permeability: 10 – 12 Micro Darcy

Sw: 39%

Thickness: 20 m

A 3-D data volume was generated over a small data-rich area, to provide a test bed to integrate with dynamic data, and guidance for expanding analysis across the entire field. This area included several horizontal wells, with extensive production, microseismic and production logging datasets, which provided good initial constraints on the reservoir and fracture stimulation geometries. These parameters were used to initialize a reservoir simulator, with monte-carlo capability. This allowed the simulator to run many iterations to determine which range of input parameters achieve the best history match. Good history matches were achieved with small to moderate adjustments to the initial parameters, which provided confidence in overall work flow. The 3-D data volume was upscaled to provide a template for creating a 2-D static realization over the entire field, and the history matching process was then repeated to calibrate inputs across the entire area. From the above values it was determined that the OGIP is between 5 – 6 bcf per spacing unit.

The calibrated completion and field description was used to optimize well location and spacing. Modeling of multiple well layouts was completed to determine the optimal wellbore spacing, with respect to resource recovery and economics. This confirmed the intuition that longer wells are more economic, so long as drill costs escalate moderately with increased length. Also, with current gas price and cost structure, the models indicate the optimum spacing between adjacent horizontal legs should be between 850-900 metres, with 500 metres between the ends of horizontal legs. As a result of this work, over 120 extended-reach well locations were identified for full field development, with horizontal well length up to 2500 metres. The well layout across the field was focused on minimizing inefficient interference between wells, combining up to four wells per pad, and avoiding sensitive areas such as rivers valleys and lakes.

Additional microseismic fracture mapping, production logs, and down-hole camera data capture is necessary throughout field development. Capturing this information in the early stages of full field development, along with single-well history matching, allowed the team to continue to evaluate the effectiveness of fracture techniques across the field, and further validate fracture height, length and azimuth. This has guided changes in the stimulation techniques to increase both height and fracture length. The result has been wells that IP at rates over 225 e3m3/d, then decline to approximately 53 e3m3/d after being on production for one year. The decline then shallows out and the wells produce for a number of years to recover between 106-142 e6m3 of gas. It is anticipated that additional data and changes will be required, to continue development in the north end of the Noel field development, where the reservoir properties change significantly.

Conclusions

The ability to bring on high rate gas wells from a low porosity, low permeability reservoir is a significant accomplishment. Good surveillance data, combined with thoughtful reservoir characterisation, enables better understanding of reservoir uncertainties, and definition of a development plan that optimizes economic performance, production delivery and resource recovery.

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